

**RESPONSE TO COMMENTS DOCUMENT FOR THE
1991 SPILL PREVENTION, CONTROL, AND
COUNTERMEASURE (SPCC) RULEMAKING**

U.S. Environmental Protection Agency

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INTRODUCTION

Purpose of this Document

The purpose of this document is to respond to comments received on the proposed rule (56 FR 54612, October 22, 1991) to revise the Oil Pollution Prevention regulation (40 CFR part 112), promulgated under the Clean Water Act (CWA). This proposed rule establishes requirements for Spill Prevention, Control, and Countermeasure (SPCC) Plans to prevent spills of oil by non-transportation-related onshore and offshore facilities into the navigable waters of the United States, adjoining shorelines, and other areas specified in the CWA. The proposed revisions involve changes in the applicability of the regulation, changes to the required procedures for completing SPCC Plans, and a new facility notification provision.

Background of this Rulemaking

The Oil Pollution Prevention regulation, or SPCC regulation, was originally promulgated on December 11, 1973 (38 FR 34164), under the authority of section 311(j)(1)(C) of the CWA. The regulation established spill prevention procedures, methods, and equipment requirements for non-transportation-related facilities with aboveground oil storage capacity greater than 1,320 gallons (or greater than 660 gallons aboveground in a single tank); or buried underground oil storage capacity greater than 42,000 gallons. Regulated facilities were those that, because of their location, could reasonably be expected to discharge oil into the navigable waters of the United States or adjoining shorelines.

We have amended the SPCC requirements a number of times, and those amendments are described in an October 22, 1991 Federal Register notice. 56 FR 54612. In the October 1991 notice, in addition to the description of past amendments, EPA proposed new revisions that involved changes in the applicability of the regulation and the required procedures for the completion of SPCC Plans, as well as the addition of a facility notification provision. The proposed rule also reflected changes in the jurisdiction of section 311 of the Act made by amendments to the Act in 1977 and 1978. We have finalized some of those proposed revisions, with modifications, in this rule.

Organization of the Comment Response Document

To develop this document, we first reviewed the letters received in the public docket. We then identified relevant issues raised by the commenters based on the content of the proposed rule. Finally, we developed responses to these summaries, carefully addressing the issues in each issue category. The following pages present the comments and responses.

We arranged the document according to the subjects listed in the Table of Contents. We assigned a reference number to each letter we received. We include reference numbers in the summaries to identify the commenters who addressed each issues. For

letters that addressed numerous issues, the corresponding letter number will appear multiple times throughout the document.

In this comment response document, the “current rule” means part 112 as codified in the most recent edition of the Code of Federal Regulations, as amended by any subsequent part 112 final rule published in the Federal Register since that codification and preceding the publication of this final rule.

Category I: Phase One and its relationship to Phase Two

Background: In the wake of the 1988 Ashland Oil Spill in Floreffe, Pennsylvania, we formed the Oil Spill Prevention, Control, and Countermeasure (SPCC) Program Task Force (the Task Force) to examine Federal regulations addressing oil spills from aboveground storage tanks (ASTs). This Task Force recommended that we distinguish guidance from required provisions, establish more technical requirements for all facilities subject to the oil spill prevention program, and require facility-specific oil spill contingency planning. Further, having found that we lacked an adequate inventory of regulated facilities, the Task Force recommended that we collect information on regulated facilities (for example, the number of ASTs at a facility). Finally, the Task Force recommended that we strengthen our facility inspection program better to identify violations and encourage compliance. A subsequent General Accounting Office (GAO) report contained similar recommendations.

As we explained in the 1991 Preamble, we decided to address the Task Force and GAO recommendations in two phases. In Phase One, we addressed those oil program provisions we could change without performing substantial, additional data gathering. As an element of Phase One, we proposed to require elementary contingency planning of a kind already in most SPCC Plans. In Phase Two, we implemented new mandates arising under the Oil Pollution Act of 1990 (OPA), including requiring substantial contingency (or response) planning. In 1991, we also requested comments on the relationship between Phase One and Phase Two. We issued the Phase Two or facility response plan (FRP) rules in 1994. 59 FR 34070, July 1, 1994, codified at 40 CFR 112.20 and 112.21.

Comments: *Timing of Phases.* “This second phase should be expedited to provide the increase prevention and containment that will result from improved SPCC plans.” (L1) We should avoid timing constraints that would require regulated owners and operators to produce a Phase One plan, a Phase Two plan, and perhaps, a third plan to meet state-specific requirements. (67, 79, 91, L10) The requirement for contingency plans should be phased in, allowing each facility to delay actual preparation until the next statutorily-mandated SPCC Certification. (L20)

Facility Notification.

Premature. Notes that OPA responsibilities have not yet been delegated to EPA. “Until such a delegation is made, the Agency cannot determine what its responsibilities will be. At this time, it is simply unreasonable for the Agency to burden the regulated community with a notification process which is not necessary.” (42, 91, 141, 167, 182) “Until EPA has outlined its data needs and how the information will be used under Phase Two, expanding the notification requirements at this time is unwarranted, unjustified and unnecessarily costly.” (167)

Timely. “Requiring this additional information during Phase I (instead of deferring to Phase II), will enable the Regions to have more time to develop a matrix for determination of facilities posing significant harm/significant and substantial harm. Of all the information requested on the notification form, the additional information listed above is most likely to be confusing to the regulated community, and hence the Regions should be afforded as much lead time as possible to clarify and troubleshoot the screening data submitted.” (168)

Public hearings. “In addition, since EPA offers these proposed rules based only on the views of a governmental task force with no representation of the regulated community, and since EPA’s rules seek to impose burdens on the regulated community as a class based on one large, unfortunate bulk storage incident, Cyprus respectfully requests that appropriate public hearings be held.” (35)

Response: *Timing of Phases.* We appreciate the comment that supported our early efforts to collect information on SPCC-covered facilities. However, because the OPA-mandated deadlines made it necessary for us to concentrate our efforts on promulgating the Phase Two rule; we issued a Phase Two proposed rule in 1993 (58 FR 8824, February 17, 1993), and a Phase Two final rule in 1994 (59 FR 34070, July 1, 1994).

Facility Notification. We have decided to withdraw the proposed facility notification requirement because we are still considering issues associated with establishing a paper versus electronic notification system, including issues related to providing electronic signatures on the notification. Should the Agency in the future decide to move forward with a facility notification requirement, we will repropose such requirement.

Public hearings. Public hearings on the rule were unnecessary due to the extensive written response we received, elucidating all sides of most issues.

I-A Coordination with other agencies

Comments: Asks us to coordinate the Phase Two rulemaking with other Federal and State regulatory activities, reasoning that government entities should avoid creating conflicting requirements and duplicating efforts. One State noted that it had received many comments on its requirements. (102, 193, 193, L10).

Response: We did coordinate the Phase Two rulemaking with other agencies. See the preambles to the 1993 proposed rule and 1994 final rule, and 1994 Response to Comment document for details.

I-B Worst case scenario

Comments: *Worst case planning.* “ACMS believes that facilities with adequate secondary containment should not be required to install leak detection monitors or

prepare and submit a plan for responding to the largest foreseeable discharge.” (51) “Our experience in assisting facilities after a spill has shown that many of them anticipated - and planned for - a spill of far less serious magnitude than the one that actually occurred. Accordingly, 3M believes the SPCC regulation should expressly require the calculation of a worse case scenario as part of each contingency plan.” (61)

Equipment. “3M believes the SPCC regulation should require each contingency plan to document the availability of enough sorbent material and other equipment to manage a worst-case spill.” (61)

Response: *Worst case planning.* We agree that an SPCC facility should not have to plan for the worst case scenario. Contingency planning following the provisions of part 109 requires planning for “varying degrees of response effort depending on the severity of the oil discharge.” 40 CFR 109.5(d)(4). We require worst case scenario planning for higher risk FRP facilities. We addressed comments and issues concerning a worst case discharge in our FRP rulemaking.

Equipment. Part 109 requires provisions that include the “identification and inventory of applicable equipment, materials and supplies which are available locally and regionally,” and “an estimate of the equipment, materials and supplies which would be required to remove the maximum oil discharge to be anticipated.” 40 CFR 109.5(c)(1)-(2).

I-C: Changing *should* to *shall*

Issues: In §112.7 of the current rule, we set general guidelines for the preparation and implementation of a Plan. In the 1991 proposal, we substituted the words *requirements* and *shall* for the words *guidelines* and *should*.

Comments: *Support for proposal.* “All the major federal reports following the Ashland Oil spill recommended that SPCC requirements be more specific so they could be better enforced. Commendably, EPA has in several places in the SPCC proposal put in mandatory language. In several other places, however, EDF urges EPA to use language that would make certain provisions mandatory, rather than retaining flexibility which may result in adverse impacts on the environment.” (27, 44, 53, 67, 148, 185, L17)

Opposition to proposal. “API also suggests that the proposed new requirements as discussed in this rule remain as recommendations only for such facilities designated as ‘small’ according to this definition and/or that all the newly proposed ‘shalls’ (as in the current SPCC regulation) for all such ‘small facilities’.” (67) The existing guidelines should be relaxed if we change *should* to *shall*. (101) Stresses the need for “practical flexibility.” Our original intent was to use *should* to provide a flexibility that would end with the change to *shall*. (110, L27, L27) A set of mandated principles is inconsistent with good engineering practice. “(G)ood engineering practice begins with the base requirements and develops the most practicable solution.” (45, 170)

Guidance documents. “...(D)iscretionary provisions might be better set forth in a separate guidance document, so as not to confuse the regulated community.” (27)

Substantive change. The change is not merely a clarification in rule language. The proposal is a substantive change for which we failed to give proper notice. The change from *should* to *shall* would impose a new regulatory burden on an owner or operator by requiring that he modify an existing SPCC Plan and facility. It would be “inappropriate for the EPA to issue a final rule until fair public notice and opportunity for comment has been given.” (32, 35, 63, 127, L27)

New costs or burdens. The change would substantially increase costs for production facilities. (28, 101, 110, 125, 146, 189, L27) This increase in costs would be enough to shut down some facilities. (28, 110) We have no substantive basis to justify making the current provisions mandatory. (101, 125, 189) It is more cost effective for the facility owner or operator to retain discretion in selecting the exact requirements necessary for the specific facility location. (125, 173) We have underestimated the costs of the changes. (125, L27)

Small facilities. Recommends that *shall* remain *should* for small facilities. (91, 116, 133, 173, 182) New requirements “should not apply to production facilities with tanks of 1,000 barrels (42,000 gallons) or less.” (91) We should allow the owner or operator of a small or medium size facility more discretion than owners or operators of “large bulk oil storage facilities with over 42,000 gallons of capacity.” (116) We should limit analysis requirements to “tanks larger than 660 gallons and electrical equipment larger than 10,000 gallons because it is impractical and unnecessary to do such analyses for all smaller units.” (125) “The ‘should’s’ to ‘shalls’ change should not apply to small production facilities... with less than 3,000 barrels of oil storage capacity.” (133) We should exempt facilities with less than 1,000 barrels of oil storage capacity. (173)

Response: *Support for proposal.* We appreciate commenter support of the change from *should* to *shall*. We believe that we must retain flexibility for a deviation when an owner or operator faces unique circumstances. No single design or operational standard can be prescribed for all non-transportation-related facilities.

Substantive change. We disagree that the change is either substantive or contrary to legislative intent. Section 311(j)(1)(C) of the Act authorizes the President and, through delegation, EPA, to establish “procedures, methods, and equipment and other requirements for equipment to prevent discharges of oil and hazardous substances from vessels and from onshore facilities and offshore facilities, and to contain such discharges.” That authority is ample to provide the basis for a mandatory SPCC rule, that is, a rule that establishes “requirements ... to prevent discharges.” We also disagree that the proposed rule failed to provide proper notice and comment. The preamble to the 1991 proposed rule fully explained the rationale for the proposed change (56 FR 54620, October 22, 1991), and numerous commenters responded. Furthermore, we have always interpreted and enforced our rules as mandatory requirements.

EPA recognizes, however, that this clarification may result in certain owners or operators of regulated facilities recognizing for the first time that they have been and are subject to various provisions of part 112. Such owners and operators should, of course, take all necessary steps to come into compliance with this part as soon as possible. If an owner or operator reports to EPA that he is out of compliance with part 112, he may qualify for a significantly lesser penalty under EPA's policy entitled "Incentives for Self-Policing: Discovery, Disclosure, Correction and Prevention of Violations" that was published at 60 FR 66706, on December 22, 1995. Furthermore, in exercising its prosecutorial discretion, the Agency always takes into account the good faith and efforts to comply of an owner or operator who has been in noncompliance with applicable laws and regulations.

Good engineering practice. We disagree that mandatory requirements are inconsistent with good engineering practice. We continue to allow deviations from most substantive rule requirements, based on good engineering practice (§112.7(a)(2)) or impracticability (§112.7(d)).

New costs or burdens. We disagree that this editorial change imposes any new regulatory burdens or costs because it imposes no new requirements. Nor will the clarifying change add to the information collection burden – it remains the same.

Small facilities. We disagree that the *should to must* change will impose new requirements or costs for small facilities. We have modified the applicability thresholds in the rule so that many small facilities are no longer covered. In addition, we have included general deviation provisions in §112.7(a)(2) and (d).

I-D Ashland oil spill should not be the basis for changes to the SPCC rule

Comments: *Ashland spill.* "The thickness of the Ashland lower chime was more than 1 inch. On the other hand, oil and gas field tanks, are fabricated from 10 gauge steel (0.10 inches thick). Steel of this thinness is not impact or thermal stress sensitive because of ease of rolling thin steel plates. Accordingly, an Ashland type spill is extremely likely to occur in oil and gas operations. Additionally, EPA, in the preamble, cites does not data demonstrating such spills or releases are liable to occur in E&P operations." (31, 34, 110, 114).

Actual risk, major spills. In proposing changes to part 112, we should assess actual situations that threaten public health and the environment. (52, 139) We should have different SPCC Plan requirements for facilities based on different risks to human health and the environment. (86) We should make part 112 address the prevention of potential major oil spills only, adding that significant changes in the SPCC rule would not "improve containment facilities insofar as Appalachian Producers are concerned." (101) Supports clarification that "SPCC plans are required (not voluntary) of facilities which pose a certain potential harm to navigable waters if oil is released from storage tanks." (164)

Small facilities, exploration and production facilities. Regulations promulgated as a result of the Ashland oil spill should not apply to small aboveground tanks. (28, 69, 79, 101, 110) The proposed regulation unduly burdens small facilities, borderline sized facilities, facilities distant from waterways, or facilities in rural areas with construction and equipment standards that apply to Ashland-type facilities. (32, 72) We developed the proposed changes to prevent large Ashland-type spills. The proposed changes are not applicable to oil and gas operations which have small volumes of stored oil (110), or exploration and production (E&P) facilities which are generally not situated near major waterways (110, 114).

Response: *Ashland spill.* As noted in the preamble to the 1991 proposed rule, we reevaluated part 112 as a consequence of findings and recommendations by the SPCC Task Force formed in the aftermath of the Ashland spill, and of similar findings in a GAO report. Although the Task Force report focused on preventing large, catastrophic spills; the report addressed many aspects of the Federal oil spill prevention, control, and countermeasure program. The Task Force report was one impetus for the 1991 proposed rule, however the proposed rules in issue were meant to address broader issues than the Ashland spill and similar spills. See 56 FR 54612-3, October 22, 1991, for a detailed discussion of the reasons supporting the 1991 proposal.

Actual risk, major spills. The changes to the rule do address actual situations that threaten public health and the environment. A facility may have different SPCC Plan requirements based on different risks to human health and the environment. We disagree that the rule should address the prevention of potential major oil spills only. Small discharges of oil may be harmful to the environment.

Small facilities, exploration and production facilities. We disagree that small facilities or oil and gas E&P facilities should fall outside of the SPCC program structure. Such facilities store or use oil and may be the source of a discharge as described in §112.1(b). Therefore, they must be subject to part 112.

Potential harm. A facility posing a reasonable possibility of a discharge as described in §112.1(b), and meeting other applicability criteria, is subject to the rule.

Category II: Proposed Notification requirements - §112.1(e)

II - A: General comments

Background: In 1991, EPA proposed to require that any facility subject to its jurisdiction under the Clean Water Act which also meets the regulatory storage capacity threshold notify the Agency on a one-time basis of its existence. This type of notice is separate from the notice required at 40 CFR 110.3 of a discharge which may be harmful to the public health or welfare or the environment. We did not propose any change to §110.3.

We proposed that facility notification include, among other items, information concerning the number, size, storage capacity, and locations of ASTs. The proposal would have exempted from the notification requirement information regarding the number and size of completely buried tanks, as defined in §112.2. The rationale for notification was that submission of this information would be needed to help us identify our universe of facilities and to help us administer the Oil Pollution Prevention Program by creating a data base of facility-specific information. We also asked for comments regarding the form on which notification would be submitted, and on various possible items of information that could be included besides the ones proposed. Lastly, we asked for comments on alternate forms of facility notification. 56 FR 54614-15.

Comments: *Support for proposal.* There is generally no current procedure whereby we could identify the universe of sites subject to the SPCC rule, and an inventory of these facilities is necessary. (27, 44, 51, 53, 62, 91, 107, 121, 135, 154, 164, 168, 181, 182, L5, L10, L11)

Additional information.

Age of containers. “The age of tanks may not correspond to its potential to spill. Depending on the product stored, thickness of plate, type of construction, and any repairs or reconditioning done, a tank’s age is not a good indication of soundness.” (51)

Adverse weather. “The question of adverse weather is subjective. What may be one facilities [sic] adverse weather may be another’s normal weather. The potential should be identified by the local emergency planning committee or the US geological service [sic].” (51)

Cost of additional information. Asking for more information would increase the reporting burden and raise compliance costs to the tens of millions. (125)

Environmentally sensitive areas. “These locations may be unknown to the facilities and should be identified by the local emergency planning committee.” (51) We proposed to require the owner or operator to provide additional information (i.e., location of environmentally sensitive areas, potential for adverse

weather) which is “completely beyond reason.” These requirements would be costly and time consuming. (31, 34) Opposes following items on the notification form: spill histories, age of tanks, location of environmentally sensitive areas, and potential for adverse weather. (75) A general request for information on environmentally sensitive areas and the potential for adverse weather would not help the development of Area Plans, because any response was likely to be speculative. (103)

LEPCs, other emergency responders. We should require an owner or operator to submit the SPCC Plan to the appropriate Local Emergency Planning Committee (LEPC). (43) On-scene Coordinators (OSCs) should inform LEPCs of SPCC rule violations. (L1) We should encourage facilities and LEPCs to conduct exercises together, in conjunction with OSCs and local fire departments. (L1, L11)

SERCs, OSROs. We should require owners or operators to submit the proposed notification information to State Emergency Response Commissions (SERCs) (27, L11), oil spill response agencies (27), and States (154). This information will help States identify regulated facilities. (L11)

Other owners. Notification should include names of the “owner of the facility, owner of the improvements at the facility, and the owner of the land at the facility. ... Perhaps one of the most significant landowners in the country who is prejudiced by the absence of a requirement for landowner involvement in the preparation of an SPCC Plan is the United States Government. ” (43)

PEs. We should require an engineer employed by the owner or operator to prepare and sign the notification. (75)

Placards. We should require an owner or operator to display a placard that includes ownership information and a unique facility identification number. (154)

Product stored. We should require information on the product stored in each tank and how it is delivered to the facility. We should collect tank data similar to the data we collect for underground storage tanks. (111)

SPCC compliance. The notification form should include: “an affidavit signed by a member of management within the owner or operator’s management certifying that the facility’s SPCC Plan has been prepared in accordance with all relevant provisions of 40 CFR part 112 and has been placed in effect....” (43)

Address. Suggests use of longitude or latitude, or Universal Transverse Mercator system, or a mailing address for a facility without a street address. (78, 101, 116, 121, L11)

Alternatives

On-site surveys. We should obtain additional information through statistically-representative sampling using on-site surveys. (L12)

Other Federal, State, and local sources. “If the Agency needs additional information for its database, such as MSDS, it can certainly obtain this from the myriad of other federal, state, and local databases for which we are required to submit information.” (161)

NRC records. “For example, records available at the National Response Center and other published sources may be used to identify areas of the country and/or locations where there significant use and releases of oil exist.” (155)

SARA duplication.

SARA duplicative. “I have never received one request for explanation of any SARA submitted information from LEPCs or fire departments.” (11) Further that this type of information is readily available without the SARA Title III reporting requirements (e.g., through exploration or production facilities). “Similar information required by the proposed notification is already reported under other programs, such as SARA.” (27) “Notification requirements have essentially been fulfilled by the SARA Title III regulations.” (28) The proposed rule is duplicative of SARA Title III regulations. (101) We should exempt owners or operators reporting through SARA Title III from any part 112 notification requirements. (113) Asks us to consider modifying the SARA Title III reporting requirements to satisfy our need for additional notification information. (118) Recommends that we permit using the Tier II form or proposed Appendix B to meet the proposed SPCC one-time notification requirement. (145) Opposes the notification requirement because we already have the requested information in the forms of SARA 311 and 312 reports. (187) SPCC-covered facilities pose a hazard equivalent to the hazard at a facility with a threshold amount of an *extremely hazardous substance* (EHS). (L1)

SARA not duplicative. States presently are preparing and maintaining data bases that the public does not use or want. With the exception of Local Emergency Planning Committees (LEPC) in large cities, no one uses the SARA Title III data. (110) SARA section 311/312 submissions were intended for the public and not to notify the Federal government of environmental threats posed by oil storage facilities. (168)

SARA and 313. Recommends that if we decided against accepting the SARA Title III form in lieu of the proposed notification form, we should let

owners or operators submit the SPCC and section 313 reports at the same time. (71)

State regulatory agencies or industry trade association surveys. (31, 42, L17)

Threshold for notification.

42,000 gallons. We are creating an unnecessary burden for ourselves and industry by requiring notification from all SPCC facilities. We should require notice only for facilities with more than 42,000 gallons of bulk storage capacity. We should require notice for small and medium size facilities only if there has been an oil spill from the facility within the preceding three years. (114, 116)

100,000 gallons. (136)

Applicability.

Discharge history. We failed to explain in the notification form that part 112 does not cover a facility unless it is reasonably likely to discharge oil into U.S. navigable waters (and meets the other SPCC program criteria). We should address the connection between part 112 applicability and the likelihood that a facility may discharge oil into navigable waters. (48) The notification provisions apply to facilities that “may” discharge harmful quantities into navigable waters. In the rule, we should clarify how we intend to determine which facilities “may” discharge harmful quantities and who will make this determination. (111) We should regulate facilities that have had spills, rather than those that have not had spills. (132)

SPCC facilities. We should require notice for any facility for which an SPCC Plan is required. (43) We should require the notification form only for a part 112 facility. (149)

“Unacceptable risk.” Asks us to decide what constitutes “unacceptable risk,” rather than requiring an owner or operator to register all aboveground tanks. We should use a given facility’s reported spill history as *a priori* criterion for determining which tanks the owner or operator must register. (132)

Dun & Bradstreet numbers. Exploration and production facilities rarely have Dun & Bradstreet numbers. (42, 58, L12)

Enforcement. To ensure notification, many States penalize those who deliver regulated substances to non-compliant UST facilities. (76) We should consider focusing upon non-reporting owners or operators rather than imposing an additional burden on industries already heavily-regulated. (162)

Facility diagrams. Section 112.1(d) should be rewritten because it seems to require otherwise exempt facilities to comply with facility notification requirements, such as providing facility diagrams. (133)

Format. Owners or operators will copy the notification form from the Federal Register, and will not submit it as a one-page, double-sided form. (27) Suggests the following: “(P)lease return the notification form to EPA unfolded in a 9-inch by 12-inch envelope.” (48) We should permit submitting a computer-generated copy of any final notification form and provide for electronic data submission. (101) EPA and USCG should use the same form. (171)

Hazardous chemicals. We should revise our discussion of petroleum products in the Preamble, because crude oil is not a “hazardous chemical,” nor is it subject to SARA Title III reporting requirements. (34)

Information collection burden. We underestimated the burden of completing and submitting the notification form. (31, 34, 35, 48, 86, 187, 192) If we require more information, we would increase the reporting and record keeping burden on industry. (79, 125, 164) Compiling more information, in turn, would mean increasing the time for submitting the notification form. (34, 95, 102, 168, 191, L7)

Navigable waters. There is no definition of navigable waters on the form, making it difficult to answer questions concerning them. (31, 41, 48, 58, 62, 67, 79, 85, 86, 107, 146, 160, L17)

Unreasonable distance. “The categories for reporting distance to navigable waters exceed reasonable distances. Facilities ‘more than 10 miles’ from navigable waters will rarely, if ever, reasonably be expected to discharge oil in quantities that may be harmful, into or upon the navigable waters of the United States. This is also probably true beginning at category 4—‘½ miles’.” (42) We should specify a minimum distance to navigable waters, on the theory that only facilities within a certain distance would have a reasonable possibility of discharge to such waters. (42, 125)

Opposition to proposal.

Differing facilities. We should issue another proposal with different requirements for different kinds of facilities. (31, 86)

Exploration and production facilities. Drilling rigs move from location to location as often as every few months. (67, 85, 91)

Duplicative requirement. It is unnecessary, because the information sought might be better obtained from other sources, e.g.: State sources (101, 111, 113, 165, 166, 188, L15); SARA Title III reports (58, 70, 71, 89, 101, 113, 114, 145, 162, 165, 169, 187, 188, 192, L12, L15); NPDES permits (56, 145); underground storage tank regulations (149); emission inventory programs (25); industry trade

association surveys (31, 160, and 161); fire regulatory authorities (65); DOT's maps and records rulemaking (L30); and the Minerals Management Service (133). Proposal includes duplicative reporting requirements. (131)

Electric utilities. Because hundreds of thousands of utility facilities will be required to submit notification forms, our proposal would impose a substantial burden on electric utilities. Our proposed reporting requirement would cost the utility industry several million dollars. (125)

Format. The notification form does not provide the information that the EPA Task Force report recommends we collect, nor is its collection of AST information as comprehensive as the form used for underground storage tank (UST) notification under Appendix I of 40 CFR part 280. (44) Section 112.1(e)(2) should read: "The written notice shall be provided either by submitting a copy of the facility's 312 report or by using the EPA form." (71)

Inventory, not capacity. Opposes using the information obtained through the SARA Title III notification requirement as a substitute for the SPCC one-time notification requirement because the SARA Title III program measures inventory, not capacity. Some tanks may not be in use, may not be filled to capacity, or may store a non-oil product. Therefore, we would not receive a correct estimate of potential discharge from SARA Title III submissions. To reduce the paperwork burden, we should explore alternative filing methods, including accepting the SARA Title III form instead of the proposed Appendix B notification form. (51)

Jurisdictional objections. Opposes the notification requirement, and asserted that the proposal would apply to facilities not subject to the SPCC rule. (L12)

Minimum necessary. The initial notification requirements should be minimal and limited to the information in Sections I, II, and III of Form B. (136)

Obsolescence. The information collected through the notification form would quickly become obsolete, but requiring updated facility notification forms when changes occur would be too burdensome. (187, 191, 192)

Small facilities. The benefit of having this information for small facilities is not great enough to justify requiring these facilities to expend the resources to prepare this information. Recommends that we initially require that a facility exceeding a given storage capacity (e.g., 42,000 gallons) submit this information. We could use this initial information to evaluate the usefulness of the information for all facilities. (58, 67, 78, 85, 91, 105, 109, 114, 115, 136, 182) Small facilities may not be able to employ sufficient staff to notify us automatically before facility operations begin. (101, 165, L15)

Terrorists. Putting the number and location of oil storage tanks in an easily accessible database could provide an “intelligence windfall” to terrorists and other enemies of the U.S. (132)

Wasteful. The proposed notification requirements in §112.1(e) are wasteful, burdensome, and serve no oil pollution prevention purpose. (31)

Outreach. We should conduct outreach, patterned after the UST program, to ensure that owners or operators are aware of the proposed requirement. (L6) We should establish an information hotline for the regulated community, in case individuals have questions on how to complete the notification form. (168) We should also request information on oil spills. Linking facility characteristics to spill events would help us develop regulations and define the universe of facilities most in need of oversight. (175)

Owner or operator. Requests clarification on who must provide notice when the owner or operator of the facility are not the same. (33, 48, 115, 116)

Permanently closed tanks. “Does the Agency intend that information on permanently closed tanks be included in this notification?” (84)

Program administration. We “found in review(ing)...the SPCC program that...numbers, storage capacities, and locations of aboveground oil storage facilities are needed to effectively administer the program” (56 FR 54614, Column 3). Asks what we meant by “effectively administer(ing) the program.” (110)

SIC codes. We should omit the three “extra” SIC code boxes from the notification form, to avoid confusion (33, 87); there were no codes listed for edible oil facilities (137); and the codes listed were misleading in that they did not cover all possible industries regulated (155).

Accuracy. EPA used inaccurate SIC codes. (67, 85, 102)

Small containers. There is no space on the form for containers less than 250 gallons. Asks whether we intend to exclude containers under 250 gallons from the rule. (76) We should establish a *de minimis* capacity for new facilities subject to this regulation, which would require giving notification within six months of beginning operations. (L7)

States, notice to. We should require that a copy of the notification form be sent to the State Emergency Response Commission (SERC) and Oil Spill Response Agency. Sharing notification information with SERCs would benefit EPA and the States. (27) We should require an owner or operator to inform the State when he sends EPA a notification form. Alternatively, we should compile notices we receive and provide that information to the State. (52)

Storage capacity. Requests clarification on whether only aboveground tanks had to be included in the facility description. (13) Asks us to clarify whether total aboveground storage capacity includes those tanks that currently store or will store oil, or tanks capable of holding any substance. (33, 115, 143) Recommends modifying the wording to read “tanks that store oil.” (33) We should require that an owner or operator state in the Plan, “the total aboveground storage capacity of the terminal, the total of such capacity that could be used for oil, and the total of such capacity at the time of reporting that is actually in oil storage.” (143) Tank size ranges are not divided according to the sizes necessary to determine if a facility is required to prepare a facility-specific plan as outlined in §112.1, that is, 1,320 total gallons or 660 gallons for a single tank. (154) Asks if additional storage capacity would trigger a new notification. (134, 165, 167)

Temporary or partial storage. EPA should provide direction regarding partially-filled tanks or seasonally inactive tanks in Parts II and III of the form. (33) To require an owner or operator to comply with the proposed notification requirements for temporary storage created during an emergency oil spill response, would be impractical and slow down the response effort. (60)

Timetables.

Before operations begin. Small operators may not be able to employ sufficient staff to notify us automatically before facility operations begin. (101, 165, L15) We should set a notification schedule for such facilities based on the new volume of oil or oil product storage. If the upgraded onsite storage capacity exceeds 10,000 gallons, the notification deadline should be prior to installation, but adds capacity that trips the part 112 threshold. If the upgrade onsite storage exceeds 1,320 gallons, the notification deadline should be within 30 days of installation. (23) Requiring notification before operations begin at a location would result in generating useless, duplicative, and contradictory information. (31)

Eighteen months. (86)

Electrical equipment. Asks whether we would classify oil-filled equipment like transformers and oil circuit breakers as oil storage tanks. If they are, completing the notification form for each facility with oil-filled equipment (substations) would take substantially longer than two months and asked for more time to complete the form. (66) If we regulate facilities with electrical equipment under part 112, it would take six months to a year for those facility owners or operators to gather the information required for the notification form. (125)

Electronic format. We should give more time to submit the notification form and should develop an electronic form for owners or operators to scan. (L11)

Environmentally sensitive areas. Facility owners or operators needed more than 12 months from the rule’s effective date to provide information on

environmentally sensitive areas and adverse weather. (34) If we require submission of information on environmentally sensitive areas and adverse weather on Form B, we should extend the time to comply commensurate with the amount of additional information required. (95, 102) If we require submission of information on environmentally sensitive areas and the potential for adverse weather, we should give owners or operators six more months to collect the information so that data are accurate. (L7)

Multiple facilities. “For many owners of multiple oil production facilities, it will be impossible to complete the notification process within the two-month time frame proposed. An extension of the deadline for filing notifications should be considered if an owner operator is filing more than 500 individual facility notifications. ... We propose a six month deadline.” (27) Disagrees with the need for a separate notification form for each facility. (58, 71, 78, 101, 145, 165, 188, L12, L15)

Nine months. Suggests a nine-month lead time for submitting the form, starting from the effective date of the final regulation. (L12)

Phase-in. The two-month submission period was unrealistic. We should have phased reporting, because we would be unable to process the many thousands of notifications we would receive within two-months. (58) Although it is logical to expect the owner or operator of a new refinery to notify us before beginning operations, it is unreasonable to expect such a notice for a facility that is operating already. (23, 28, 101, 167, L15)

Risk. We should establish reporting times based upon risk thresholds, rather than subject both large and small quantity storage facilities to the same two-month deadline. (23)

Six months. Notification within a six-month period after beginning operations would be more reasonable, if, in fact, any notification is necessary. (101)

Six months to a year. With the existing storage capacity threshold for aboveground storage so low, many facility owners or operators subject to the rule may not be aware of it. We should consider adopting new notification thresholds or a reporting deadline based on storage capacity at a facility. Notification deadlines for facilities with more than 100,000 gallons of capacity could be due six months to one year earlier than for facilities with storage capacity less than 100,000 gallons. Many smaller storage facility owners or operators lack the resources to address this regulation. (57, 67, 75, 91, 190, 181)

Six months. (48, 52, 71, 75, 77, 92, 105, 107, 116, 128, 133, 135, 145, 150, 155, 167, 182)

Three or four months. (87, 90, 93, 143)

Twelve months. (31, 34, 189, L2, L30)

Two months. Suggests changing the final sentence of the subsection to the following: "With respect to any facility subject to this part which commences operations after [insert date 60 days after date of publication of final rule] or becomes subject to this part after [insert date 60 days after date of publication of the final rule] as a result of increased storage capacity, the operator must provide notification to the Regional Administrator before beginning facility operations."

(42) Favor the notification requirement and argue that the proposed notification form and corresponding two-month response time are appropriate. (54, L7) We should revise the date of notification for new facilities to within 60 days of the date when a covered tank is placed into operation. (145) Two months would be insufficient to collect and submit such information. (191) Questions the proposed two-month time frame. (41, 48, 54, 58, 71, 89, 103, 175, 181, 187)

Updates to notification. Facility notification should be current, and an owner or operator should let us know about any change in storage capacity, operation, or ownership within 30 days. These commenters recommended making a full notification once, and amendments as necessary. (27, 33, 89, 159, 185, L11)

Copies requested. Several States requested copies of the notifications EPA would receive (52, 185, L10)

Vegetable oil and animal fat facilities. Including vegetable and animal oils in the definition of *oil* was unreasonable. The CWA's context shows that Congress did not intend to address vegetable and animal oils under the SPCC program. (42) We should ask for less information from vegetable oil facilities (i.e., name, address, number of tanks, and total capacity of tanks). (56)

Response: *Withdrawal of proposal.* We have decided to withdraw the proposed facility notification requirement because we are still considering issues associated with establishing a paper versus electronic notification system, including issues related to providing electronic signatures on the notification. Should the Agency in the future decide to move forward with a facility notification requirement, we will repropose such requirement.

II - B: Content of notification form

Comments: *Addresses and zip code.* "It won't be possible to give an address and zip code of the facility [sic] due to their rural location." (28, 42, 101) A single regional production office can monitor or operate many different production facilities. We should clarify whether the Agency wants the address of the production office or the legal description of where the facility is located. (42) Crude oil production storage facilities do not have a name, address, and zip code. (58, 187) We should ask for separate facility location and facility mailing addresses so we could later avoid mailing

information to an unattended facility. (101) We should allow either the facility address or location to suffice for notification purposes. (133)

Authority. Some of the information we proposed requesting is beyond our authority to collect (e.g., facility latitude and longitude, location of environmentally sensitive areas, and potential for adverse weather). (L30)

Private wells. If we adopt the notification requirement, we should not include private water wells in the list of water suppliers that the owner or operator must notify. It would be highly impractical and prohibitively expensive for the owner or operator to attempt to locate every downstream private water well. (28, 101)

Dun & Bradstreet. Dun & Bradstreet numbers are not available for crude oil production storage facilities. (58) Obtaining Dun & Bradstreet numbers can be very labor intensive or impossible. (42, L12) We should make identification of Dun & Bradstreet numbers optional and not punish facility owners or operators if they do not provide Dun & Bradstreet numbers or if they provide inaccurate ones. (L12)

Longitude and latitude. The facility's latitude and longitude should be included on the notification form. (27, 62, 121, 135, 154, 168, L11)

Miscellaneous items. We should collect aboveground storage tank information, such as tank status (e.g., currently in use), capacity, age, material of construction, method of construction (e.g., field erected), and substance stored. (44) Supports a requirement that the owner or operator submit additional information on the notification form, including facility latitude and longitude, location of environmentally sensitive areas, potable water supplies, presence of secondary containment, spill history, leak detection equipment and alarms, age of tanks, and potential for adverse weather. (168) Opposes a requirement that the owner or operator provide additional information, such as the latitude and longitude of the facility, location of environmentally sensitive areas and potable water supplies, presence of secondary containment, spill history, leak detection equipment and alarms, age of tanks, potential for adverse weather, and any other additional information. (31, 33, 34, 35, 41, 42, 48, 51, 53, 54, 57, 58, 62, 66, 67, 75, 79, 82, 83, 86, 87, 89, 91, 95, 101, 102, 103, 110, 115, 118, 121, 133, 136, 137, 155, 164, 167, 181, 182, 183, 191, L12, L30).

Navigable waters. Asks us to clarify what we meant in the proposed rule when we stated that an owner or operator should provide the "distance to nearest navigable waters" in proposed §112.1(e)(2)(iii). Asks whether we meant the owner or operator should consider tributaries, wetlands, and sloughs when determining the distance to nearest *navigable waters*. (62) We should define *navigable waters* on the form. (76) A facility's distance from "navigable waters" may be meaningless when storm drains are located next to the facility because spilled oil can travel directly through a storm drain to navigable waters. (79) Information on distance to navigable waters is limited and open to various interpretations. (39, 48, 79) An owner or operator may be incapable of identifying the nearest navigable water. (42, 58) Notification should "not include the

distance of the facility to the nearest navigable waters, but the distance of each tank from the nearest navigable waters.” (L2) Requesting the distance to navigable waters for the nearest tank would unduly skew the database for certain industries. It would be better to obtain information on estimated average distances for each category in Section II of the notification form. (L12)

“Site information.” We should make some “technical corrections” to improve the notification form, but gave no specifics. (48) We should ask only for site information and should include “a question regarding the need to implement a facility SPCC Plan.” (89)

Response: See the response to II-A, above.

Category III: Discretionary provisions

III - A: Stating the design capabilities of drainage systems

Background: In 1991, we requested comments on a recommendation that we did not include in rule text that an owner or operator of an onshore facility (other than a production facility) describe the design capability of a facility drainage system in the SPCC Plan if the system is relied upon to control spills or leaks.

Comments: *Support for description.* We should require that owners or operators describe the design capabilities of facility drainage systems in the SPCC Plan. Such a description would help identify all paths of escape for discharges at a facility, assess the spill retention capacity of the facility's containment system, and identify the risks to the public of a discharge. (47, 51, 76, 80, 95, 135, 168, L17)

Large or small facilities. EPA should require more detailed drainage information for large facilities with storage capacity exceeding 1,000,000 gallons. At these facilities, a Professional Engineer (PE) should identify all paths of escape for oil discharges, assess the spill detention capacity of the facility, identify the risks of a release to the public, and develop topographic surveys of each facility and the area immediately surrounding the facility. (47)

Requirement or recommendation. We should recommend – rather than require – an owner or operator to describe facility drainage system design capabilities in the SPCC Plan. The provision is redundant since other SPCC rule provisions already address this issue. (95, 175) Describing the facility drainage system design capabilities would create unnecessary paperwork and complicate the Plan. (25, 34, 74, 155)

Storm event. SPCC Plans should describe the maximum storm event the drainage system can handle. It would be essential to know if the capabilities of the existing system were adequate to handle storm, spill, or leak flows. (80)

Response: The question of description of the design capabilities of drainage systems for onshore facilities other than production facilities is adequately covered by rules pertaining to drainage. See, for example, §§112.7(a)(3) and (4), 112.7(b), 112.8(b), and 112.10(c). Therefore, we will not promulgate any additional requirements on this subject. These provisions generally require that a facility owner or operator design the facility drainage system to prevent discharges, or if prevention fails, to contain the discharge within the facility.

We note that for facilities with a storage capacity exceeding 1,000,000 gallons, we do, in some cases, require more detailed drainage information (in the facility response plan).

III - B: Different requirements for large and small facilities

Background: In 1991, we requested comments on whether to create a category for large facilities and to require more stringent provisions for such facilities. We also requested comments on whether such provisions should be discretionary for smaller facilities.

Comments: *Authority.* Neither the language nor the legislative history of the CWA compels us to regulate all facilities at which oil is present. (65, 125) The statute confers substantial discretion on us to determine the types of facilities that pose sufficient risk to surface waters to warrant the SPCC regulatory controls. (125)

Opposition to proposal. All facilities can pose major impacts to human health and to the environment, regardless of storage capacity. (168)

Unnecessary. Such provisions are unnecessary because no risks exist for which the discretionary provisions were proposed. (35, 82)

Support for proposal. “Contrary to EPA’s concern, §311(j)(1)(C) of the Clean Water Act does not prohibit different requirements based on facility size.” (65) We should regulate facilities based on storage capacity differences. We should distinguish between small and large facilities. Even small cost increases can have a detrimental economic effect on small facilities. (62, 65, 82, 115, 145, 164, 173, 175, L6) EPA’s departure from the Task Force’s recommendations to regulate facilities based on size “undermines EPA’s assertion that the proposed regulations are justified by the Task Force Report.” (32) Supports regulation of facilities that could reasonably be expected to discharge oil in harmful quantities. (75) We should have separate requirements for small and large facilities. “Aboveground tanks used by production wells are considerably smaller than those used in the refining and marketing sectors. Further, these wells typically are remote from both major surface waters and population centers, thus posing significantly less risk to the environment than larger facilities.” (125) Cites EPA’s finding in the 1988 Underground Storage Tank (UST) final rule that “tanks that hold large amounts of regulated substances do pose a relatively larger potential danger to human health and the environment than other, small tanks.” (See 53 FR 37111.) We should use the UST finding in the SPCC rule. (125, 170)

Risk. We should focus on facilities that pose the greatest risk to navigable waters, rather than focus on facilities of a particular size. (35, 50, 62, 79, 82, 114, 125, 130, 164, 167, L17) We should focus on the engineering and design of the storage and containment plan. (35) We should limit the requirements to high-risk facilities, and not to facilities with contingency plans and spill-prevention measures in place. (62) We should not propose broad changes to part 112 that would apply to all storage facilities regardless of tank size, without considering the potential impacts on navigable waters. However, the final rule should be flexible, and should account for site-specific factors and conditions regarding potential environmental impacts. (114) Instead of imposing the same requirements on all facilities regardless of facility size or level of risk, we

should design a regulatory structure to impose pollution prevention costs equal to the pollution “costs” that a facility may impose on the public. (125) By imposing the same requirements and costs on smaller, lower risk facilities as on larger, higher risk facilities regulatory costs outweigh environmental benefits. (130)

Large facilities, more stringent requirements. We should regulate large facilities more stringently because they can bear the cost of regulations more easily than smaller ones. (101) We should regulate large facilities more stringently than small facilities because large facilities pose a greater hazard to the environment than small facilities. We should modify SPCC regulations to reflect varying degrees of stringency based on facility size, and the observation that large facilities have a greater potential for causing spills and subsequent environmental damage. (32, 58, 65, 125) The proposed regulations “focus on aboveground storage tanks with a capacity of one million gallons and larger.” (108, 122)

Small facilities only. We should apply discretionary provisions to small facilities only, leaving requirements only for larger facilities. (51, 80, 103, L17)

Small facilities, more stringent requirements. Small facilities may pose a greater spill potential because small facility owners or operators do not have resources to ensure proper equipment installation. (76) A large facility is more likely to have sufficient human resources and equipment than a small facility. In the event of a spill, a large facility can provide immediate response, thus minimizing the spill size. (102)

Response: *Large or small facility regulation, in general.* We have decided not to regulate facilities differently based merely on storage capacity, provided that the capacity is above the regulatory threshold of over 1,320 gallons. This decision is based on environmental reasons. Small discharges of any type of oil that reach the environment can cause significant harm. Sensitive environments, such as areas with diverse and/or protected flora and fauna, are vulnerable to small spills. EPA noted in a recent denial of a petition for rulemaking: “Small spills of petroleum and vegetable oils and animal fats can cause significant environmental damage. Real-world examples of oil spills demonstrate that spills of petroleum oils and vegetable oils and animal fats do occur and produce deleterious environmental effects. In some cases, small spills of vegetable oils can produce more environmental harm than numerous large spills of petroleum oils.” 62 FR 54508, 54530, October 20, 1997. Describing the outcome of one small spill of 400 gallons of rapeseed oil into Vancouver Harbor, we noted that “...88 oiled birds of 14 species were recovered after the spill, and half of them were dead. Oiled birds usually are not recovered for 3 days after a spill, when they become weakened enough to be captured. Of the survivors, half died during treatment. The number of casualties from the rapeseed oil spills was probably higher than the number of birds recovered, because heavily oiled birds sink and dying or dead birds are captured quickly by raptors and scavengers.” 62 FR 54525.

A small discharge may also cause harm to human health or life through threat of fire or explosion, or short-or long-term exposure to toxic components.

Other factors. Finally, EPA notes that the rule affords flexibility to an owner or operator of a facility to design a Plan based on his specific circumstances. It allows him to choose methods that best protect the environment. It permits deviations from most of the mandatory substantive requirements of the rule when the facility owner or operator can demonstrate a reason for nonconformance, and can provide equivalent environmental protection by other means. Consequently, both small and large facilities have the opportunity to reduce costs by alternative methods if they can maintain environmental protection. Because smaller facilities may require less complex plans than larger ones, their costs may be less. In addition, small facilities storing or using 1,320 gallons or oil or less will not be subject to the rule.

III-B-1 Defining “small” and “large” facility

Comments: *Alternate small facility definitions.*

Less than 126,000 gallons. Less than 126,000 gallons of total aboveground storage capacity. (133)

Less than 30,000 gallons. Less than 30,000 gallons of total aboveground storage capacity. (82)

Less than 10,000 gallons. Less than 10,000 gallons of total oil storage capacity. (L17).

“Less than 42,000 gallons.” Less than 42,000 gallons of total aboveground storage capacity (34, 67, 78, 133, and 167); less than 42,000 gallons of total oil storage capacity, provided no single tank is greater than 12,600 gallons (58); If we define a small facility as one with less than 42,000 gallons of total aboveground storage capacity, we would reduce the burden on numerous small operations, without limiting the protection afforded by spill prevention, containment, and countermeasures. (78) Less than 42,000 gallons total storage capacity, provided no single container is greater than 250 gallons. (133)

242,000 gallons. We should define a *small facility* as a “facility with a total of 242,000 gallons or less of oil, provided no single container has [a] capacity in excess of 20,000 gallons.” (70)

Large facility definition.

More than 10,000 gallons. A large facility should be one with a capacity of 10,000 BBI (4.2 million gallons). This approach would be more reasonable and would recognize the greater threat presented by a spill occurring at a facility with that amount of storage capacity. (34)

More than 42,000 gallons. Supports the 42,000 gallon capacity criteria, but suggests that small and large facilities be further delineated. (62) We should define a large facility as one with a regulated storage capacity of more than 42,000 gallons. (78,105)

Response: Because we do not differentiate requirements merely due to facility size, there is no need to define large or small facility.

III-B-2 Small facility exemption

Comments: *Support for small facility exemption.* We should exempt small facilities from this regulation. (28, 46, 58, 67, 70, 82, 101, 67) Such an exemption would be consistent with the Task Force findings. (28) An exemption would reduce the regulatory burdens because owners or operators would then be subject to local requirements. (46) We should exempt small facilities because we would realize a more significant environmental benefit from taxpayer's dollars by focusing scarce funds and resources on larger facilities. (58) In setting an exemption, we should consider size and whether the facility is one or more miles from surface waters or outside of the coastal zone. (167, 174)

Opposition to proposal. We have not provided a "reasoned" analysis for applying the proposed revisions to small facilities. (58) We should gather additional information to justify our changes to the SPCC program. Cites the GAO report, and asserts that we need more information to decide which tanks to regulate most strictly and inspect most often. (101) We did not provide a historical background, or an understanding of exploration and production or gas processing industry spills. (114)

Recommendations instead. Questions whether all of the proposed changes in the rule are necessary for all types and sizes of oil storage facilities, including smaller tank configurations such as those found at oil and gas production sites, quick oil change facilities, and other points of oil sales and distribution. (70) The newly proposed requirements should remain as recommendations for small facilities. (67, L18)

Risk. The regulation should not focus on small, aboveground storage tanks, which pose fewer environmental risks than large tanks. (50, 67, 79) We should apply the revisions to large facilities only, and maintain the status quo for smaller, less environmentally threatening facilities. (58) The current SPCC regulations and industry standards provide sufficiently for continued environmental protection. (67) We should exempt certain smaller, low risk tanks and temporarily closed tanks. (71) We should exempt facilities that have no reasonable potential to discharge oil into navigable waters. (75)

We should not require small facilities to have SPCC Plans, as long as the facility's HAZWOPER or hazardous waste contingency plan contains oil-related spill response procedures. (62, 124) "Problems exist" in the proposed regulations, with respect to smaller aboveground tanks in the 660 to 10,000 gallon range capacity storage (108), and with smaller aboveground tanks in the 660 to 20,000 gallon range capacity storage (122). Storage tanks in the 600 to 4,200 gallon storage capacity range neither have the same potential adverse impact nor require the same intense scrutiny as very large tanks. (105) Our data do not demonstrate that small facilities cause significant discharge hazards to navigable waters. (31, 34, 101, and 110)

Small shop-built containers. Smaller, factory-constructed tanks have fewer field construction problems and hold less oil than large tanks. Eliminating small tanks from the proposed requirements would result in a more cost-effective regulatory program with environmental protection equivalent to part 112 requirements. (164)

Response: As noted in this section, we are not regulating small facilities differently from large facilities. See the discussion in section V - G of this document concerning the rise in the regulatory threshold.

Recommendations instead. We are not including any recommendations in the rules because we do not wish to confuse the regulated public as to what is mandatory and what is discretionary.

Risk. We do consider the size of a facility and whether its location gives rise to the reasonable possibility of discharge as described in §112.1(b), for example the distance of the facility from the nearest navigable waters or adjoining shorelines.

III-B-3 Alternative regulatory approaches for small facilities

Comments: *Specific rules, production facilities.* We should develop a subset of regulations to specifically address operations of small oil and gas production facilities with a storage capacity of less than 42,000 gallons. (28)

Less than an SPCC Plan. Facilities with hundreds of small capacity storage tanks (50 barrels or less) should be required to meet spill prevention measures but not prepare an SPCC Plan, or meet the other requirements associated with the SPCC rules. The potential for major environmental damage from these facilities is remote because these facilities hold small volumes of oil. (71)

Response: *Specific rules, production facilities.* Because we do not regulate facilities based on size, there is no need for regulations specifically addressed to any type of facility for that reason. We note that different sections of the final rule address production facilities. For example, §112.9 addresses requirements for onshore production facilities. Section 112.10 addresses requirements for onshore oil drilling and workover facilities. Section 112.11 addresses requirements for offshore drilling, production, or workover facilities.

Less than an SPCC Plan. We disagree that meeting the rule's requirements without preparing and implementing a Plan would protect the environment. There would be no way to enforce those requirements in the absence of a written facility-specific Plan.

Category IV: General applicability and notification

Category IV: General applicability and notification

IV- A: Scope of the rule - “Harmful quantities” - §112.1(a), (b), (c), and (d)(1)

Background: Section 112.1(a) of the current rule seeks to prevent oil discharges into the “navigable waters of the United States or adjoining shorelines.” In §112.1(a), (b), and (c) of the 1991 proposed rule, we proposed to extend the geographic scope of the SPCC regulation to conform with the 1977 CWA amendments. CWA section 311(b)(1), as amended in 1977, prohibits oil or hazardous substance discharges into United States navigable waters or adjoining shorelines, or into the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States, including resources under the Magnuson Fishery Conservation and Management Act.

We also proposed to revise the term *harmful quantities* in §112.1(b) to reflect the 1978 amendments to the CWA. The revised term – *quantities that may be harmful, as described in part 110 of this chapter* – includes oil discharged in quantities that violate applicable water quality standards, cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines, or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines. See 40 CFR 110.3. Amendments to the CWA also reflected the broadening of quantities that may be harmful to include those not only harmful to the “public health or welfare,” but also to the environment.

IV-A-1 Extending the geographic scope of the rule

Comments: *NRDAs.* Proposal “will allow for more clarity in determining which facilities are subject to the SPCC requirements. Also, the inclusion of natural resources sets the stage for the implementation of Natural Resources Damage Assessments, as required by OEPA.” (27)

Opposition to proposal. “If natural resources in this context means all Federal lands, then this extension would bring under the scope of 40 CFR 112 a significant number of operating facilities which did not previously require SPCC plans. The proposed rule, however, states that EPA assumes existing facilities that would be brought under 40 CFR 112 regulation already have SPCC Plans for other reasons, and thus expects the rule to affect only new facilities. This is incorrect; many existing facilities on federal lands do not have SPCC plans because they have had no need and no regulatory requirement for them. For example, our facilities in arid areas where there is little or no surface water or rainfall lack such plans because of their location and the nature of their activities. Thus, the regulations should be revised to better distinguish which existing or new facilities warrant SPCC plans based on their location and the nature of their activities.” (63)

Coastal zone.

Exclude. "...RMOGA suggests consideration be given to adding requirements that the exempt facilities be those located 1 or more mile(s) from surface waters (defined as those for which water quality standards are assigned) or those located outside of the coastal zone (as already defined by regulation)." (167)

Include. "The suggested reference to the coastal zone is appropriate because this is a clearly defined area and is the area where greatest benefits from the proposed rules can be expected." Areas less than one mile from a river, lake or stream should be excluded from the coastal zone definition. (174)

Magnuson Act resources only. Expansion of applicability to include natural resources "will surely result in another unnecessary workload on the judicial system over the years. Perhaps the replacement of this item with the following wording will minimize or eliminate the impact: '...or any resources under the Magnuson Fishery Conservation and Management Act'." (L12)

Response: We also believe that few, if any, new facilities will be subject to the rule because of its extension to facilities with the potential to affect certain natural resources. We believe that most affected facilities are either already subject to the rule, or not subject to our jurisdiction due to a Memorandum of Understanding between EPA, the U.S. Department of Transportation (DOT), and the U.S. Department of the Interior (DOI), which assigns jurisdiction over most of those facilities to DOT or DOI. See 40 CFR part 112, Appendix B.

We have amended this provision to be consistent with the revised statutory language found in sections 311(b)(1) and (c)(1)(A) of the CWA. This rule focuses on preventing discharges to navigable waters, adjoining shorelines, the exclusive economic zone, and natural resources belonging to, appertaining to, or under the exclusive jurisdiction of the United States. Once a prohibited discharge of oil occurs and affects such natural resources, the NRDA provisions of OPA sections 1002(b)(2)(A) and 1006 apply. The National Oceanographic and Atmospheric Administration has promulgated a set of regulations which govern the process for conducting NRDA's under the OPA. 15 CFR part 990.

IV-A-2 Broadening the concept of harmful quantities

Comments: *Support for proposal.* "Pratt & Whitney also agrees with the revision of section 112.1(b) definition of 'harmful quantities' to reflect those of the Clean Water Act amendments. This effort at consistency helps business achieve compliance." (118)

Opposition to proposal. Our proposal would "replace a fairly objective standard with a very subjective conditional standard," and asserted that the language in the current rule

provides adequate environmental protection. (35) We should expand the definition of a harmful quantity to include used oils or waste forms of all subject products. (87) One person asked that we describe how we will determine whether a quantity “may” be harmful, and who will make this determination. (111) While our proposed change implies a standard of reasonable risk, the applicable part 110 definition “creates an entirely different standard.” Part 110 provides that any discharge that causes a film or sheen upon or discoloration of the surface of the water or adjoining shorelines is deemed to be a discharge of oil that “may be harmful.” (125) We should modify the applicability standard to base the program on “real” or “reasonable” risks to navigable waters, rather than on “*de minimis*” or “theoretical” risks, to reduce the regulatory burden. (98, 125, 170)

Facility notification. Our proposal would subject more owners or operators to the §112.1 notification requirements. (65, 98)

Manmade structures. Our risk criteria in determining applicability to the SPCC requirements are too broad, particularly with regard to the sheen test and the “prohibition of considering manmade structures” to evaluate a facility’s risk. (98) We should change the regulation to permit an owner or operator to consider manmade structures that provide containment in determining whether a facility could reasonably be expected to have a spill event. Such a consideration is appropriate “where the structures are inherent in the design of the facility and serve functional and operational purposes.” (78, 98, 125, 156, 170)

NPDES rules. Our definition of harmful quantities does not appear to reflect the National Pollutant Discharge Elimination System (NPDES) storm water discharge permit requirements. We should consider the protection provided by NPDES permits and the Underground Storage Tank (UST) regulation (part 280) sufficient. (76)

Paperwork. Our proposal appears to conflict with section 101(f) of the Clean Water Act (CWA) that requires EPA to minimize paperwork, duplication, and delays in implementing the statute. (65)

Reasonable expectation of discharge. We should clarify the statement in the proposed rule that part 112 applies to owners or operators of non-transportation-related facilities, “which due to their location could reasonably be expected to discharge oil in quantities that may be harmful, described in part 110.” This is particularly important because of the associated penalties for noncompliance. (62, 89, 98, 111, 149, 154)

Sheens. What makes a sheen harmful? (62)

Response: *Support for proposal.* We appreciate commenter support.

Applicability. Quantities of oil that may be harmful include oil discharged in quantities that violate applicable water quality standards, cause a film or sheen upon or

discoloration of the surface of the water or adjoining shorelines, or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines. The revision we have made to this provision simply reflects the 1978 amendment to the CWA, which requires us to determine quantities of oil that *may* be harmful, rather than quantities of oil that *will* be harmful. The harm a discharge may cause will vary from site to site depending upon, for example, the sensitivity of the environment, the water conditions, etc. These quantities apply to discharges of used oil or waste oil as well as any other type of oil. The 1987 amendments to part 110 incorporated this statutory change, but retained the same objective criteria as before – violation of applicable water quality standards, a film or sheen on the surface, or a sludge or emulsion below the surface. Thus, this revision to our SPCC rule should not result in a change in the number of regulated entities.

Facility notification. We have withdrawn the proposal for facility notification.

Manmade structures. To allow consideration of manmade structures (such as dikes, equipment, or other structures) to relieve a facility from being subject to the rule would defeat its preventive purpose. Because manmade structures may fail, thus putting the environment at risk in the event of a discharge, there is an unacceptable risk in using such structures to justify relieving a facility from the burden of preparing a prevention plan. Secondary containment structures should be part of the prevention plan.

NPDES rules. We do consider the protection provided by NPDES permits and the Underground Storage Tank (UST) regulation (part 280) in the rule. An owner or operator may use his Best Management Practice Plan (BMP) prepared under an NPDES permit as an equivalent SPCC Plan, if the plan provides protections equivalent to SPCC Plans. Not all BMP plans will qualify, as some BMP plans might not provide equivalent protection. NPDES permits without BMP plans would not qualify.

We exempt from the SPCC program completely buried tanks subject to all of the technical requirements of 40 CFR part 280 or a State program approved under 40 CFR part 281.

Paperwork. We disagree that our proposal conflicts with section 101(f) of the Clean Water Act (CWA) that requires EPA to minimize paperwork, duplication, and delays in implementing the statute. The expansion of the geographical scope of the rule tracks the 1978 statutory amendments.

Reasonable expectation of discharge. We do not believe that any rule which exempts facilities beyond any particular distance meets the intent of the statute. The locational standard in the rule is whether there is a reasonable possibility of discharge in quantities that may be harmful from the facility. A facility that is more than one mile from navigable waters might well fit within that standard. For example, piping or drainage from that facility might lead directly to navigable water. If discharged oil may reach or does reach navigable waters, adjoining shorelines, or protected resources, the distance which the discharged oil travels is irrelevant.

Sheens. See the discussion of the dangers of discharged oil under the discussion of the definition of “oil” in today’s preamble.

IV-A-3 Electrical equipment

Background: In the preamble to the 1991 proposal, we noted that certain facilities may have equipment such as electrical transformers that contain significant quantities of oil for equipment operation – not storage. We said that operational oil-filled equipment should not be subject to §§112.8(c) or 112.9(d), which address bulk storage containers at onshore facilities. Consequently, an owner or operator of a facility with equipment containing oil for ancillary purposes need not provide secondary containment for this equipment nor implement the other provisions of proposed §§112.8(c) or 112.9(d). However, oil-filled equipment must meet other applicable SPCC requirements, including the general requirements in §112.7 and 112.7(c), to provide appropriate containment and or diversionary structures to prevent discharged oil from reaching navigable waters.

Comments: We should be consistent with the part 280 requirements, and exclude from part 112 electrical equipment that requires mineral oil to operate. Otherwise, we would be imposing a substantial regulatory burden on owners or operators. We excluded electrical equipment from part 280, rationalizing that these types of tank systems pose a relatively low level of risk compared to other types of storage tanks. Electrical substations and other installations are not *facilities* as defined in the proposed rule. Electrical equipment does not consume oil, and therefore is not covered under the SPCC program. (130, 138)

Response: We disagree that oil-filled electrical equipment, as well as other operational equipment, is not subject to the SPCC rule. We have amended §112.1(b) to clarify that using oil, for example operationally, may subject a facility to SPCC jurisdiction as along as the other applicability criteria apply, for example, oil storage capacity, or location. Such a facility might reasonably be expected to discharge oil as described in §112.1(b). Therefore, the prevention of discharges from such facility falls within the scope of the statute. We also defined *facility* in the final rule to include equipment in which oil is used or stored.

IV - B: Exemption of completely buried containers - §112.1(d)(2)(i) and (d)(4)

Background: Under §112.1(d)(2)(i) and (ii) of the current rule, a facility with a completely buried storage capacity of 42,000 gallons or less of oil *and* with an aboveground storage capacity of 1,320 gallons or less of oil, provided no single container has a capacity in excess of 660 gallons, is exempted from the requirements of part 112. In §112.1(d)(2)(i) of the 1991 proposal, we proposed to exclude the capacity of underground storage tanks (editorially changed to “completely buried tanks,” as defined in §112.2) subject to all of the technical requirements of 40 CFR part 280. (Subterranean vaults, bunkered tanks, and partially buried tanks are considered aboveground storage containers for purposes of part 112. See the definition discussion in Category VI of this document.) We also proposed in §112.1(d)(4) to exclude from part 112 applicability, completely buried tanks, subject to the technical requirements of part 280.

Comments: *Support for proposal.* “We also support the exemption of the underground storage tanks that are subject to 40 CFR part 280. This will eliminate duplicate regulation of these tanks.” (27,35, 53, 66, 67, 71, 75, 82, 92, 95, 102, 103, 106, 107 115, 118, 125, 133, 135, 136, 164, 173, 175, 182, 190, L24, L29)

Consistency. We should be consistent in our approach to regulating ASTs and USTs. For example, under part 280, UST systems that store fuel solely for use by emergency power generators do not have to comply with the “release detection” requirements in part 280. Therefore, we should “defer AST systems that store fuel solely for use by emergency power generators from the listed secondary containment options.” (69)

Editorial suggestion. Supports the proposed exclusion of USTs from part 112, but we should include the provision in §112.1, rather than in the §112.2 definitions. (121)

Equivalency. “EPA itself states that the UST program offers protection ‘equivalent’ to that provided by the SPCC program. That being the case, EPA has every reason to avoid the confusion that would result as the regulated community implements a scheme under which it is difficult to determine the applicability of the regulation.” (35, 57, 71, 173)

Reduced paperwork. Supports proposal to exclude certain USTs from part 112 coverage and from the SPCC threshold calculation, because it would substantially decrease the amount of unnecessary paperwork that an owner or operator generates and that we review. (103)

Opposition to proposal. Opposes the §112.1(d)(2)(i) and (d)(4) exclusions. (43, 44, 47, L4, L5)

Confusing. “...(T)he exemption of USTs regulated under 40 CFR 280 means that a facility owner may have some tanks that are exempt from SPCC requirements and some not. ... This could get really confusing!” (111)

Costs. We should not exempt facilities with underground storage tank (UST) installations whose total capacity exceeds 42,000 gallons, because the rulemaking docket contained no economic justification for this and Congress enacted no law requiring the change. (43)

Groundwater. “Exempting all combinations and sizes of USTS from the proposed Oil Pollution regulation in an effort to avoid overlapping federal rules may appear attractive in a paperwork reduction sense. But this regulatory approach does not consider some basic characteristics of the natural resource: groundwater eventually becomes surface water. Hydrologically, oil released into underground waters may migrate to surface water within minutes or months. Certain classes of USTs could seriously damage the nation’s ground and surface water resources if an accident were to occur in the absence of emergency responsive provisions.” Urges no further action “until further legislative remedies are in place.” (L4)

UST rules insufficient. UST regulations are insufficient to protect navigable waters from oil discharges. The part 280 requirements lack adequate emergency response, training, contingency planning, recordkeeping, and spill prevention planning requirements, diking of fuel transfer areas; fuel transfer area operational procedures, illumination of fuel transfer areas; storm water drainage system design; posting of vehicle weight restrictions in areas where there is underground piping and/or design of underground piping to withstand vehicular loadings; or a requirement for an application of “good engineering practice.” (24, 43, 44, L4) “Also, response actions for underground storage tanks leaks should remain part of the written SPCC Plan.” (27) An owner or operator of a tank system subject to part 280 does not have to comply with the part 280 release detection requirements. Under the 1991 proposal, these owners or operators would not have to prepare an SPCC Plan or install release detection systems. (76) The leak detection and tank installation requirements for buried tanks should be consistent with part 280. (111) “The Agency should not hold a position that UST program regulation of those facilities would satisfy the spill prevention requirements of 40 CFR 112.” (L5)

Emergency response. “Certain classes of USTs could seriously damage the nation’s ground and surface water resources if an accident were to occur in the absence of emergency responsive provisions.” (L4)

PE certification. “...(T)he UST regulation does not require the development and certification of spill prevention plans as is required under Oil Pollution Act regulations.” (L4)

Applicability.

Piping. “Under the proposed rule, it is unclear whether or to what extent the piping connecting USTs and ASTs in such circumstances is regulated under the SPCC program. If such piping is subject to the leak detection requirements for USTs under 40 CFR part 280, then ILMA believes the piping should remain exclusively within the jurisdiction of the UST program and should be exempted from the SPCC regulations.” (48)

Partially buried tanks and bunkered tanks. “Bunkered tanks and partially buried tanks should be covered by the UST program since ten percent or more of the product is below grade either in the tank or pipeline. Tanks under the UST program should be adequately protected to prevent and minimize releases to the environment. Tanks not covered by the UST program should be considered aboveground storage tanks (provided that they are not permanently closed) for purposes of the SPCC regulation and should be subject to the requirements.” (190)

Clarification. Proposed §112.1(d)(2)(i) is confusing. Asks whether it is coverage by part 280 that permits an owner or operator to exclude the capacity of a buried tank from the 42,000 gallon threshold, or the lack of such coverage. (28, 31, 165, L15)

Definitions. “EPA should devise a regulatory scheme under which the same definition of underground storage tanks is used in the UST and SPCC regulatory programs....” (57)

Delegation. We should consider implementing a program for ASTs similar to the UST program. The UST program, which “franchises” programs to the States, provides a flexible approach to enable and encourage States to carry out delegated program activities. (111)

“In compliance with.” We should change proposed §112.1(d)(2)(i) and(d)(4) to state that we exclude owners or operators of USTs *in compliance with* the technical requirements of part 280, rather than excluding owners or operators of USTs *subject to* the part 280 technical requirements. (76)

Outreach. We should design and implement an outreach program based on the UST program’s outreach efforts to give owners or operators time to learn about the program and to prepare and implement an SPCC Plan before the regulatory compliance deadlines. (L6)

Response: *Support for proposal.* We appreciate commenter support. In response to the commenter who said that we should exclude USTs through a provision in §112.1, rather than through the §112.2 definitions, we agree. That is exactly the action we proposed and adopted.

Regulatory jurisdiction. To eliminate any possible confusion over regulatory jurisdiction, we explain in today's preamble (see the above background discussion) which containers in a facility are subject to 40 CFR part 280 or a State program approved under 40 CFR part 281, and which are subject to part 112.

Opposition to proposal.

Discretionary authority. Today's rule (see §112.1(f) in today's preamble and section 2 of the 1993 Comment Response Document) provides the Regional Administrator with the authority to require any facility subject to EPA jurisdiction under section 311 of the CWA, regardless of threshold or other regulatory exemption, to prepare and implement an SPCC Plan when necessary to further purposes of the Act.

UST rules insufficient. As we noted in the preamble discussion of §112.1(d)(1)(i), the UST program provides comparable environmental protection to the SPCC program. While not all aspects of the programs are identical, the UST program ensures protection against discharges as described in §112.1(b), and protection of the environment. Therefore, dual regulation is unnecessary. In response to commenters asserting that UST rules lack provisions concerning contingency planning; emergency response; certain recordkeeping requirements; and other alleged deficiencies, we disagree. The UST rules have numerous safeguards addressing the commenter's issues.

Contingency planning. While it is true that UST rules do not require contingency planning, spills and overfills of USTs resulting in a discharge to the environment are much less likely as a result of those rules. An owner or operator of an underground storage tank subject to 40 CFR part 280 or a State program approved under 40 CFR part 281 was required to install spill and overfill prevention equipment no later than December 22, 1998. 40 CFR 280.20 and 280.21. The use of this equipment will greatly reduce the likelihood of both small and large releases or discharges of petroleum to the environment through surface spills or overfilling underground storage tanks. In addition, the UST rules place a general responsibility on the owner or operator to ensure that discharges due to spilling and overfilling do not occur. See 40 CFR 280.30.

Emergency response and release reporting. The UST rules also have several requirements related to emergency response and release or discharge reporting. The UST rules generally require that releases of regulated substances be reported to the implementing agency within 24 hours. As part of the initial response requirements (found at 40 CFR 280.61), an owner or operator must take immediate action to prevent further release of the regulated substance and must identify and mitigate fire, explosion, and vapor hazards.

Reporting and recordkeeping. In addition to the reporting requirements mentioned above, there are numerous reporting and recordkeeping requirements

in the rules governing underground storage tanks. Among these are: corrective action plans; documentation of corrosion protection equipment; documentation of UST system repairs; and, information concerning recent compliance with release detection requirements. Thus, the UST rules have significant reporting and recordkeeping requirements, including specific requirements related to spills and overfills.

Transportation rules. In addition to the EPA UST rules, the U.S. Department of Transportation has hazardous material regulations related to driver training, emergency preparation, and incident reporting and emergency response. Training regulations, for example, can be found at 49 CFR part 172, and loading and unloading regulations can be found at 49 CFR 177.834 and 49 CFR 177.837. These regulations apply, for example, to truck drivers delivering gasoline or diesel fuel to gas stations with underground storage tanks.

Piping, ancillary equipment, and containment systems. EPA has modified the scope of the proposed exemption for completely buried tanks (which are excluded from the scope of the SPCC rule if they are subject to all of the technical requirements of 40 CFR part 280 or a State program approved under 40 CFR part 281) by clarifying that the exemption includes the connected underground piping, underground ancillary equipment, and containment systems, in addition to the tank itself. This modification is consistent with the definition of underground storage tank system found at 40 CFR 280.12. In addition, this clarification is responsive to the comment which asked that the piping be included in the exemption.

Clarification. We disagree that §112.1(d)(2)(i) is confusing. If a completely buried tank is subject to all of the technical requirements of 40 CFR part 280 or a State program approved under 40 CFR part 281, it is exempt from the SPCC rule. Otherwise, it may be subject to the rule.

Delegation. We have no authority under the Clean Water Act to delegate our program to the States, unlike the UST program. However, States may enact their own prevention programs. The Act does not preempt States from doing so.

“In compliance with.” We disagree that we should change §112.1(d)(2)(i) and(d)(4) to exclude an owner or operator of a facility with completely buried tanks *in compliance with* the technical requirements of part 280 (or a State program approved under part 281), rather than *subject to* part 280 (or part 281) technical requirements. Regulatory jurisdiction would be chaotic under a scheme measuring compliance. A facility might be in compliance one day and not the next, subjecting the facility to dual regulation.

Outreach. We agree that outreach is necessary and will conduct extensive outreach efforts after publication of this rule.

Partially buried tanks and bunkered tanks. We disagree that partially buried tanks and bunkered tanks should be considered completely buried tanks, and therefore excluded from SPCC provisions. Such tanks may suffer damage caused by differential corrosion of buried and non-buried surfaces greater than completely buried tanks, which could cause a discharge as described in §112.1(b). Such tanks are also not subject to secondary containment requirements under part 280 or a State program approved under 40 CFR part 281. There may also be accidents during loading or unloading operations, or overfills resulting in a discharge to navigable waters and adjoining shorelines. Furthermore, a failure of such a tank (caused by accident or vandalism) would be more likely to cause a discharge as described in §112.1(b). Therefore, these tanks must be regulated under the SPCC program.

We will, however, accept UST program forms, e.g., the Notification for Underground Storage Tanks, EPA Form 7530-1, or an approved State program equivalent, insofar as such form contains information relevant to the SPCC program. For example, the UST form contains information regarding corrosion protection for steel tanks and steel piping (item 12) which would be relevant for SPCC purposes. Other items on the form may also be relevant for SPCC purposes.

Effect on Facility Response Plan facilities. The exemption for completely buried tanks subject to all the technical requirements of 40 CFR part 280 or a State program approved under 40 CFR part 281 applies to the calculation of storage capacity both for SPCC purposes and for Facility Response Plan (FRP) purposes because the exemption applies to all of part 112. Therefore, a few FRP facilities with large capacity completely buried tanks subject to 40 CFR part 280 or a State program approved under 40 CFR part 281 might no longer be required to have FRPs. Calculations for planning levels for worst case discharges will also be affected. However, the Regional Administrator retains authority to require the owner or operator of any non-transportation-related onshore facility to prepare and submit a FRP after considering the factors listed in §112.20(f)(2). See §112.20(b)(1).

IV-B-1 Completely buried tanks regulated under State programs

Comments: “Although certain USTs such as heating oil tanks are deferred or exempted, because of concern for the environment and/or more stringent state regulations, these USTs may incorporate all of the technical requirements of the fully regulated USTs. If owners having exempted or deferred USTs take the necessary action to comply with the UST technical requirements, these USTs should likewise be excluded from 40 CFR 112 requirements.” (79)

Response: We agree, and have revised the rule accordingly. In §112.1(d)(4) of the final rule, we exempt from part 112 requirements (except the facility diagram) completely buried tanks subject to all of the technical requirements of State programs approved under part 281. When we proposed the part 280 exemption in 1991, few if any States had an approved program. In 40 CFR part 281 (published on September 23, 1988 at 53 FR 37212), EPA established regulations whereby a State could receive

EPA approval for its State program to operate in lieu of the Federal program. In order to obtain EPA program approval under part 281, a State program must demonstrate that its requirements are no less stringent than the corresponding Federal regulations set forth in part 280, and that it provides adequate enforcement of these requirements. Thus, we have decided to exempt also the storage capacity of USTs subject to all of the technical requirements of State UST programs which EPA has approved. By January 2000, EPA had approved 27 State programs, plus programs in the District of Columbia and Puerto Rico. The rationale for exempting the storage capacity of these facilities from the SPCC regime is because 40 CFR part 280 and the approved State programs under 40 CFR part 281 provide comparable environmental protection for the purpose of preventing discharges as described in §112.1(b).

IV-B-2 Editorial changes and clarifications

Comments: *Piping, ancillary equipment, and containment systems.* It is unclear how part 112 addresses piping that connects USTs to aboveground storage tanks (ASTs); we should exclude from part 112 regulation, piping subject to part 280 leak detection requirements. (48) Proposed §112.1(d) is unclear. (111)

Editorial reference. In proposed §112.1(d), our reference to the “first sentence of §112.7(a)(3),” appears to be incorrect. (16)

Response: *Piping, ancillary equipment, and containment systems.* EPA has modified the scope of the proposed exemption for completely buried tanks (which are excluded from the scope of the SPCC rule if they are subject to all of the technical requirements of 40 CFR part 280 or a State program approved under 40 CFR part 281) by clarifying that the exemption includes the connected underground piping, underground ancillary equipment, and containment systems, in addition to the tank itself. This modification is consistent with the definition of underground storage tank system found at 40 CFR 280.12. In addition, this clarification is responsive to the comment which asked that the piping be included in the exemption.

Editorial reference. We disagree that our reference to §112.7(a)(3) in the proposed introductory paragraph of §112.1(d) is incorrect. However, we have removed the §112.7(a)(3) reference in introductory paragraph of §112.1(d) and placed it instead in §112.1(d)(4). We thus clarify that regardless of whether a completely buried tank is excluded from part 112, the owner or operator must mark such tank on the facility diagram, if the facility is otherwise subject to part 112. (See Category X-C of this document for further discussion on facility diagrams.)

IV - C: Exemption of permanently closed containers - §112.1(b)(2) and (d)(2)(ii) - (See also section V- 11, definition of “permanently closed.”)

Background: Section 112.1(b) establishes the general applicability of part 112. In 1991, in §112.1(b)(2), we proposed that part 112 would apply to a facility with a

container used for standby storage, seasonal storage, or temporary storage, or not otherwise *permanently closed* (as defined in §112.2).

Current §112.1(d) describes the facilities excluded from part 112. In 1991, in §112.1(d)(2)(i) and (ii), we proposed that the facility threshold storage capacity would not include the capacity of underground storage tanks that are *permanently closed* (as defined in §112.2).

Comments: *Support for proposal.* “We agree that storage tanks which meet the criteria for being permanently closed ... should be exempt from 40 CFR part 112. We believe that these tanks, when properly and permanently closed, pose no danger to the public health or the environment.” (23, 36, 72, 75, 86, 90, 95, 102, 103, 118, 175, 190, L12, L24, L29)

Decommission. “Because ‘recommissioning’ of a tank requires that the Plan be amended, the need for the definition would not appear to be necessary if the wording was changed to decommission instead of permanently closed. This would provide the facility operator more flexibility without a reduction in the protection afforded.” (76)

Non-oil storage. “Any regulations should recognize that a tank does not have to be empty of all products, only oil products, to be considered ‘permanently closed’ from the standpoint of this regulation.” (51)

Tanks, not facilities. We should exclude from SPCC Plan requirements permanently closed tanks “rather than facilities where all tanks are closed.” (L24)

Temporary closure. “Pennzoil has several oil production sites where we have ceased production, but not permanently closed the site, pending more favorable economics to restart production. Under this proposal, it appears that we would have to either permanently close the unused tanks (at a cost of \$450 to \$1500 per tank) and then pay to reopen the tanks or prepare SPCC plans for empty tanks. Both of these alternatives seem unnecessary to us. ... Pennzoil suggests that instead the capacity of these tanks not be included, provided the operator can show that the tanks have been shut-in and all fluid removed down to the pipeline connection.” (71,107)

Emergency response. “...(T)he requirements for advance notification, and various construction and operating procedures are neither appropriate nor practical for temporary storage during a spill response effort.” Therefore, suggests we “exempt from the Proposed Rule temporary storage facilities used in an emergency response.” (60, 75, 103)

Frac tanks. “...(U)nless language were added to exclude fractionization tanks from the SPCC program, each time a frac tank is used or moved to a new location, a modification to the facility-specific SPCC plan would be required per 112.5(a). Frac tanks are often used to store oil for short periods of time while maintenance or workover operations are underway. The use of frac tanks is of

very short duration and does not necessarily increase the potential for a discharge.” (167)

Mining operations. “Once again, an interpretation covering drums for temporary storage poses severe practical problems for PDC, where one or two oil drums might be temporarily located at remote portions of a large mining operation, and it is impractical to maintain an up-to-date SPCC plan that addresses such drum storage and use.” (L24)

Sludge. “EPA should allow tanks which are ‘temporarily closed’ (i.e., have no free product, but contain an oil sludge) to be exempt from the operational and design requirements of these regulations.” (L2)

Who determines permanent closure. “Within its definition of ‘permanently closed’ (relative to tanks) the proposed rule would designate a number of conditions that must be met by the facility. DuPont believes that the imposition of such conditions is unnecessary and the designation of ‘permanently closed’ should be left to the facility. Facilities are liable for the release of oil and must keep plans up to date for any component of the facility which could release oil.” (155)

Response: *Support for proposal.* We appreciate commenter support.

Decommission. We disagree that the need for the definition is unnecessary if the wording were changed from *permanently closed* to *decommission*. A tank that is “decommissioned” might not meet the standards for permanent closure in the rule.

Non-oil storage. Containers storing products which are not oil are not subject to the SPCC rule.

Temporary closure. If a tank is not permanently closed, it is still available for storage and the possibility of a discharge as described in §112.1(b), remains. A tank closed for a temporary period of time may contain oil mixed with sludge or residues of product which could be discharged. A discharge from such facility could cause severe environmental damage. Therefore, it must remain subject to the rule. Nor does a short time period of storage eliminate the possibility of such a discharge.

We agree that we should exclude permanently closed containers from Plan requirements, and have revised §112.1(b)(3), (d)(2)(i), and (d)(2)(ii) to provide that permanently closed containers are excluded from part 112 requirements. A facility that contains only permanently closed containers is no longer subject to SPCC requirements.

Who determines permanent closure. We disagree that we should allow the owner or operator to designate which containers are permanently closed. We believe that a definition is necessary based on objective requirements to avoid confusion as to when

we consider a container permanently closed. Therefore, we have promulgated a definition of *permanently closed*. See §112.2.

IV - D: Exemption of Minerals Management Service (MMS) facilities - §112.1(d)(3)

Background: In §112.1(d)(3) of the 1991 proposal, we proposed to exempt from the SPCC regulation facilities subject to regulation under the United States Department of Interior's (DOI's) Minerals Management Service (MMS) Operating Orders, notices, and regulations. In general, these facilities are offshore oil production or exploration facilities. We proposed this exemption to avoid redundancy in regulation.

Under section 2(b)(1) of Executive Order (EO) 12777, the President delegated authority to various Executive Branch agencies to regulate entities covered under the CWA. See 56 FR 54747, October 22, 1991. The EO gave EPA the authority to regulate non-transportation-related onshore oil facilities. The President delegated similar authority over transportation-related onshore facilities, deepwater ports, and vessels to the United States Department of Transportation (DOT); and authority over other offshore facilities, including associated pipelines, to DOI. Before EO 12777, MMS regulated facilities on the Outer Continental Shelf (OCS) (i.e., three miles or more beyond the coast line). EO 12777 gave DOI authority for spill prevention, control, and countermeasure planning for all offshore facilities, including some facilities traditionally subject to our jurisdiction.

In a Memorandum of Understanding (MOU) between DOI, DOT, and EPA, effective on February 3, 1994, DOI redelegated to EPA the responsibility for regulating non-transportation-related offshore facilities located landward of the coast line. This MOU is found in Appendix B of the current rule. As a result of this redelegation, offshore facilities landward of the coast line remain subject to our jurisdiction. Offshore facilities seaward of the coast line are subject to DOI jurisdiction, except for deepwater ports and associated pipelines delegated to DOT.

Comments: *Support for proposal.* "The proposed revision regarding SPCC plans in the OCS is welcome. Considerable confusion regarding the need of both an SPCC plan and a MMS Spill Contingency plan exists." "The existing provisions of the MMS regarding oil spill prevention and contingency planning are comprehensive and provide a level of protection equivalent to that envisioned by EPA's proposed rules." (67, 75, 97, 110, 113, 133, 173, L12)

Opposition to proposal. "... (W)e are concerned with MMS' 'historic treatment of identified violations.' MMS failed to issue a single civil penalty since 1982. The EPA, with its mechanism and authority to impose civil penalties, should not exempt offshore oil exploration and production from the requirements of the proposed regulation. Such action would surely result in better protection of the environment." (123, 142, L13)

"More stringent." The more stringent of EPA or MMS regulations should take precedence. (L13)

Clarification. Asks which agency – EPA, DOI, or DOT – now has authority under section 311(j) of the CWA over “a portable drilling unit operating in the bed of an intermittent stream in New Mexico.” (121)

Response: *Support for proposal.* We appreciate commenter support. We have retained our original proposal, except for an editorial revision, because we believe that MMS will provide equivalent environmental protection for the facilities under its jurisdiction. MMS regulations require adequate spill prevention, control, and countermeasures that are directed more specifically to the facilities subject to MMS requirements.

In response to the commenter concerned about MMS’ enforcement record, as we noted in the 1991 Preamble, we believe that, based on an analysis of the MMS regulations (formerly known as Operating Orders), MMS requires adequate spill prevention, control, and countermeasure practices.

“More stringent.” We disagree that the more stringent of rules should take precedence unless the facility is a complex. If the facility is not a complex, then the rules of the agency with jurisdiction apply.

Clarification. To determine which Federal agency has authority over a particular type of facility, we refer the reader to Appendix B of part 112. A portable drilling unit operating in the bed of an intermittent stream would be under EPA jurisdiction, assuming it met the regulatory threshold and that there is a reasonable possibility of a discharge as described in §112.1(b) from the facility. The MOU between DOI, DOT, and EPA in Appendix B provides that we have authority to regulate non-transportation-related offshore facilities located landward of the coast line. The MOU in Appendix A defines non-transportation-related and transportation-related onshore and offshore facilities. It defines a mobile oil well drilling facility as non-transportation-related when fixed in position for drilling operations. See 35 FR 11677, July 22, 1970.

IV - E: Regulatory threshold - §112.1(d)(2)

Background: Section 112.1(d)(2) contains the regulatory threshold provisions of part 112.

Comments: *Regulatory threshold.* The threshold capacity criteria should be higher. The provision would regulate a universe of small facilities that pose no significant risk to navigable waters. (41, 125, 130, 189) Re proposed §112.1(d)(2)(i), “We do not believe EPA intended to exempt solely those facilities meeting both of the above criteria. Instead, it would appear EPA intended this to be a ‘small entity’ exemption.” Suggests replacing the word “both” with “either” in introductory language to paragraph (2). (33) Our “all-encompassing” approach would subject tens of thousands of aboveground tanks to the SPCC rule -- from small production tanks to large storage facilities at a refinery or a terminal facility. (71, 78)

Effectiveness and enforcement. “PEO feels that the inclusion of these excessively small facilities dilute the effectiveness of the program and the enforcement of larger facilities which pose a genuine threat.” (41)

Response: *Regulatory threshold.* We agree that the threshold should be higher. We have decided to raise the current regulatory threshold, as discussed in the 1997 preamble, to an aggregate threshold of over 1,320 gallons. We believe that raising the regulatory threshold is justified because our Survey of Oil Storage Facilities (published in July 1996, and available on our web site at www.epa.gov/oilspill) points to the conclusion that several facility characteristics can affect the chances of a discharge. First, the Survey showed that as the total storage capacity increases, so does the propensity to discharge, the severity of the discharge, and the costs of cleanup. Likewise, the Survey also pointed out that as the number of tanks increases, so does the propensity to discharge, the severity of the discharge, and the costs of cleanup. Finally, the Survey showed that as annual throughput increases, so does the propensity to discharge, the severity of the discharge, and, to a lesser extent, the costs of the cleanup.

The threshold change will have several benefits. The threshold increase will result in a substantial reduction in information collection. Some smaller facilities will no longer have to bear the costs of an SPCC Plan. EPA will be better able to focus its regulatory oversight on facilities that pose a greater likelihood of a discharge as described in §112.1(b), and a greater potential for injury to the environment if a discharge as described in §112.1(b) results.

We raise the regulatory threshold realizing that discharges as described in §112.1(b) from small facilities may be harmful, depending on the surrounding environment. Among the factors remaining to mitigate any potential disasters are that small facilities no longer required to have SPCC Plans are still liable for cleanup costs and damages from discharges as described in §112.1(b). We encourage those facilities exempted from today’s rule to maintain SPCC Plans. Likewise, we encourage facilities becoming operable in the future with storage or use capacity below the regulatory threshold which are exempted from the rule to develop Plans. We believe that SPCC Plans have utility and benefit for both the facility and the environment.

While we believe that the Federal oil program is best focused on larger risks, State, local, or tribal governments may still decide that smaller facilities warrant regulation under their own authorities. In accord with this philosophy, we note that this Federal exemption may not relieve all exempted facilities from Plan requirements because some States, local, or tribal governments may still require such facilities to have Plans. While we are aware that some States, local, or tribal governments have laws or policies allowing them to set requirements no more stringent than Federal requirements, we encourage States, local, or tribal governments to maintain or lower regulatory thresholds to include facilities no longer covered by Federal rules where their own laws or policies allow. We believe CWA section 311(o) authorizes States to establish their own oil spill prevention programs which can be more stringent than EPA’s program.

When a particular facility that is below today's threshold becomes a hazard to the environment because of its practices, or when needed for other reasons to carry out the Clean Water Act, the Regional Administrator may, under a new rule provision, require that facility to prepare and implement an SPCC Plan. See §112.1(f). This provision acts as a safeguard to an environmental threat from any exempted facility.

IV-E(1)-1 Alternative thresholds and criteria

Comments: *Alternatives suggested.* We should increase the capacity criterion to a number that would better reflect facilities that pose a significant risk. (41, 49)

100 gallons. "If EPA insists on promulgating the proposed regulations, then there is no justification for excluding residential fuel oil storage tanks. ... A threshold of 100 gallons should be established to include all tanks which threaten the environment." (110)

2,000 gallons. 2,000 gallons or less, provided no single container has more than 1,100 gallons. (178)

6,000 gallons. 6,000 gallons or less of aboveground storage capacity, provided tanks have secondary containment and overfill protection (79)

10,000 gallons. 10,000 gallons or less of aggregate storage capacity, provided tanks have adequate secondary containment (L17); The regulation should apply only to facilities with capacity greater than 10,000 gallons, based on individual unit size rather than accumulated volume. (L20)

30,000 gallons. 30,000 gallons or less, provided no single container has more than 15,000 gallons (82); 10,000 gallons or less of aggregate storage capacity (125, 130, 170, 189, and L18).

42,000 gallons. (23, 58, 65, 78, 80, 82, 101, 103, 109, 116, 140, 164, 175, 183, and L6) 42,000 gallons or less, provided no single container has capacity in excess of 10,000 gallons. (70) Suggests different storage capacity levels, claiming that we chose 42,000 gallons arbitrarily. (42, 102, 143, 155, 182, 190) In choosing the threshold level, we should consider a facility's proximity to navigable water or environmentally sensitive areas. This commenter also stated that we should consider a facility's use of good engineering practice in revising the regulation. (159)

50,000 gallons - underground storage. "Many of our service stations have storage tanks for gasoline and diesel fuel of 12,000 gallons a piece. If all four products are provided at a station - as most are - our service stations will come under the requirements for SPCC Plans. We do not believe that this is intended,

and would request that the gallonage requirement be increased to 50,000, not 42,000 gallons.” (177)

Animal fats, vegetable oils. “Arvin is of the opinion that non-petroleum based oils such as animal and vegetable fats and oils should be exempt from all oil 40 CFR 112 requirements.” “The statutory history of the spill control program, as well as the content of the proposed regulations, make it clear that this program was conceived and designed to prevent and manage spills involving petroleum-based oils. ... We therefore urge that the final regulations make clear that mandatory requirements are not applicable to facilities producing or storing vegetable oils.” (56, 137, 162)

Appalachian producers. The proposed requirements would be detrimental to Appalachian Producers, and we should exempt Appalachian Producers from any further requirements. (101)

Electrical equipment. “The Agency should change the aboveground storage capacity criterion to limit the applicability of the SPCC requirements to facilities with one or more aboveground oil-containing units with a capacity of more than 10,000 gallons and to limit the applicability of the SPCC requirements at such facilities to aboveground tanks or containers with a capacity in excess of 660 gallons and electrical equipment with aboveground capacity in excess of 10,000 gallons. To the extent that electrical equipment is not otherwise excluded from regulation under the SPCC program, the Agency should conditionally exclude all such equipment with a capacity of 42,000 gallons or less from regulation unless the unit of equipment has experienced one or more spill events.” (125)

Farms. “Placing unreasonable and expensive restrictions on on-farm storage poses substantial risk to the farmer’s ability to continue mechanized farming operations. We have not seen any big rush of city folks clamoring to do hand labor in the fields of this nation. Therefore, we request a reasonably crafted farm exemption from the aboveground tank rules, based on tank size and risk, such as is contained in the current underground storage tank regulations.” (73, 106, L23)

Floating fuel tanks. “It would be extremely helpful ... if the rule specifically addressed floating fuel storage, and the subjects of tank testing and diking and/or containment.” (151)

Largest unit. The risk posed by a facility is more accurately measured by the size of the largest individual unit at the facility rather than the facility’s aggregate storage capacity. The failure of one unit is extremely unlikely to cause failure of another unit because small tanks are rarely interconnected. (125)

No threshold. We should focus on setting applicability criteria by tank size, rather than facility storage capacity. (67) We should omit the capacity criterion for total storage capacity at a facility. (170, 189)

Oil-filled equipment, test tanks. We should exempt test tanks and certain oil-filled equipment from part 112 because test tanks do not store oil in bulk, and are not intended to be oil-filled. Test tanks could not “reasonably be expected to discharge oil in quantities that may be harmful.” (60)

Oil-water separators. Part 112 should include facilities that have oil-water separators connected to sanitary or storm water sewers or drains. Oil-water separators are not subject to part 280 regulations, because they are “flow-through process tanks.” (43)

Stripper oil and gas facilities. We should exempt stripper oil and gas well facilities from any new regulatory program. (113)

Treatment tanks. We should exclude facility storage and treatment tanks associated with “non-contact cooling water systems,” or “storm water retention and treatment systems.” Although the tanks are designed to remove spilled oil from manufacturing operations and parking lot runoff, the tanks contain insignificant concentrations of oil in the water. (90)

Vaulted tanks. “We would ask that the proposed rule be amended to either exempt vaulted tanks under 3000 gallons, or tanks located inside a facility with adequate secondary containment, or reduce the requirements commensurate with the risk, i.e., the size and location of the tank. ... We request that vaulted tanks or tanks with other engineering controls designed to contain product released from failure or overfill, or which meet the technical requirements of 40 CFR part 280, be exempted from these regulations. We base this request on the fact that we employ containment and controls designed to prevent our stored product from reaching either soil or water. We provide for containment and notification upon product release.” (1, 37, 49, 50, 65, 67, 72, 85, 133, 144)

Volume, not capacity. “The 42,000 gallon capacity criteria is good, but CMI suggests that a further delineation separate large and small facilities. For example, the amount of oil actually stored in a tank. Can manufacturers have large tanks, but the amount of oil varies greatly, normally only from 10 to 50 percent oil are contained in the tank.” (62) We should change the aboveground storage *capacity* threshold calculation to an aboveground oil storage *volume* calculation, so that an owner or operator would count the amount of oil in the storage container. (35, 167) We should change this threshold calculation to a *working capacity* calculation, so that an owner or operator would only count the amount of tank capacity actually used for storage. (31, 86, and 160)

Response: As explained above (see section V-E of this document), we have raised the regulatory threshold for aboveground storage capacity to over 1,320 gallons.

All containers. In response to comments, we are including a minimum container size to use for calculation of the capacity of aboveground storage tanks and completely buried containers. The 55-gallon container is the most widely used commercial bulk container, and these containers are easily counted. Containers below 55 gallons in capacity are

typically end-use consumer containers. Fifty-five gallon containers are also the lowest size bulk container that can be handled by a human. Containers above that size typically require equipment for movement and handling. We considered a minimum container size of one barrel. However, a barrel or 42 gallons is a common volumetric measurement size for oil, but is not a common container size. Therefore, it would not be appropriate to institute a 42 gallon minimum container size.

You need only count containers of 55 gallons or greater in the calculation of the regulatory threshold. You need not count containers, like pints, quarts, and small pails, which have a storage capacity of less than 55 gallons. Some SPCC facilities might therefore drop out of the regulated universe of facilities. You should note, however, that EPA retains authority to require any facility subject to its jurisdiction under section 311(j) of the CWA to prepare and implement an SPCC Plan, or applicable part, to carry out the purposes of the Act.

While some commenters had suggested a higher threshold level, we believe that inclusion of containers of 55 gallons or greater within the calculation for the regulatory threshold is necessary to ensure environmental protection. If we finalized a higher minimum size, the result in some cases would be large amounts of aggregate capacity that would not be counted for SPCC purposes, and would therefore be unregulated, posing a threat to the environment. We believe that it is not necessary to apply SPCC or FRP rules requiring measures like secondary containment, inspections, or integrity testing, to containers smaller than 55 gallons storing oil because a discharge from these containers generally poses a smaller risk to the environment. Furthermore, compliance with the rules for these containers could be extremely burdensome for an owner or operator and could upset manufacturing operations, while providing little or no significant increase in protection of human health or the environment. Many of these smaller containers are constantly being emptied, replaced, and relocated so that serious corrosion will likely soon be detected and undetected leaks become highly unlikely. While we realize that small discharges may harm the environment, depending on where and when the discharge occurs, we believe that this measure will allow facilities to concentrate on the prevention and containment of discharges of oil from those sources most likely to present a more significant risk to human health and the environment.

Animal fats, vegetable oils. A facility storing or using animal fats or vegetable oils (whether edible or not) is subject to part 112 if there is a reasonable possibility of discharge as described in §112.1(b) from such facility, and the facility meets regulatory threshold criteria. The scope of the rule encompasses all types of oils, not merely petroleum oil.

In 1995, Congress enacted the Edible Oil Regulatory Reform Act (EORRA), 33 U.S.C. 2720. That statute mandates that most Federal agencies differentiate between and establish separate classes for various types of oils, specifically: animal fats and oils and greases, and fish and marine mammal oils; oils of vegetable origin; petroleum oils, and other non-petroleum oils and greases. In differentiating between these classes of oils,

Federal agencies are directed to consider differences in the physical, chemical, biological, and other properties, and in the environmental effects, of the classes. In response to EORRA, as noted above, we have divided the requirements of the rule by subparts for facilities storing or using the various classes of oils listed in that act.

Because at the present time EPA has not proposed differentiated SPCC requirements for public notice and comment, the requirements for facilities storing or using all classes of oil will remain the same. However, we have published an advance notice of proposed rulemaking seeking comments on how we might differentiate among the requirements for the facilities storing or using various classes of oil. 64 FR 17227, April 8, 1999. If after considering these comments, there is adequate justification for differentiation among the requirements for those facilities, we will propose rule changes.

Appalachian producers, small facilities, stripper oil and gas facilities, oil-water separators. The “storage capacity” definition is applicable to both large and small storage and use capacity, no matter where located, because both types of facilities have the same possibility of discharge as described in §112.1(b). The same rationale applies to stripper oil and gas well facilities, and to oil-water separators. An owner or operator of a small facility above the regulatory threshold is subject to the rule, and needs to know how to calculate his storage or use capacity.

Farms. We also disagree that we should exempt farm operations because such operations may be the source of a discharge as described in §112.1(b). We have, however, raised the regulatory threshold to a storage or use capacity greater than 1,320 gallons, which will have the effect of exempting many small farm facilities from the scope of the rule.

Floating fuel tanks. We also note that barges which store oil, are permanently moored or fastened to the shore, and are no longer used for transportation, are no longer vessels, but bulk storage containers that are part of an offshore facility. Likewise, a container, whether onshore or offshore, which was formerly used for transportation, such as a truck or railroad car, which now is used to store oil, is no longer used for a transportation purpose, and is a bulk storage container.

Largest unit. We disagree that the risk posed by a facility is more accurately measured by the size of the largest individual unit at the facility rather than the facility’s aggregate storage capacity. More than one unit may fail at once. For example, permanently manifolded containers are designed, installed, and/or operated in such a manner that multiple containers function as one storage unit. In a worst case discharge scenario, a single failure could cause a discharge as described in §112.1(b) of the contents of more than one container.

No threshold. We disagree that we should omit the capacity criterion for total storage capacity at a facility, and instead focus on tank size. More than one container may fail at the same time due to human error or a catastrophic event whether the containers are interconnected or not. For example, permanently manifolded containers are designed,

installed, and/or operated in such a manner that multiple containers function as one storage unit. In a worst case discharge scenario, a single failure could cause a discharge as described in §112.1(b) of the contents of more than one container.

Oil-filled equipment. Types of containers counted as storage capacity would include flo-through separators, tanks used for “emergency” storage, test tanks, transformers, and other oil-filled equipment. This equipment may also experience a discharge as described in §112.1(b) and is therefore properly regulated under the SPCC program.

Treatment tanks. We agree with the commenter that certain wastewater treatment facilities or parts thereof should be exempted from the rule, if used exclusively for wastewater treatment and not used to meet any other requirement of part 112. We have therefore amended the rule to reflect that agreement (see §112.1(d)(6)). No longer subject to the rule would be wastewater treatment facilities or parts thereof such as treatment systems at POTWs and industrial facilities treating oily wastewater.

Many of these wastewater treatment facilities or parts thereof are subject to NPDES or state-equivalent permitting requirements that involve operating and maintaining the facility to prevent discharges. 40 CFR 122.41(e). The NPDES or state-equivalent process ensures review and approval of the facility's: plans and specifications; operation/maintenance manuals and procedures; and, Stormwater Pollution Prevention Plans, which may include Best Management Practice Plans (BMP).

Many affected facilities are subject to a BMP prepared under an NPDES permit. Some of those plans provide protections equivalent to SPCC Plans. BMPs are additional conditions which may supplement effluent limitations in NPDES permits. Under section 402(a)(1) of the CWA, BMPs may be imposed when the Administrator determines that such conditions are necessary to carry out the provisions of the Act. See 40 CFR 122.44(k). CWA section 304(e) authorizes EPA to promulgate BMPs as effluent limitations guidelines. NPDES rules provide for BMPs when: authorized under section 304(e) of the CWA for the control of toxic pollutants and hazardous substances; numeric limitations are infeasible; or, the practices are reasonably necessary to achieve effluent limitations and standards to carry out the purposes of the CWA. In addition, each NPDES or state equivalent permit for a wastewater treatment system must contain operation and maintenance requirements to reduce the risk of discharges. 40 CFR 122.41(e).

Additionally, some wastewater is pretreated prior to discharge to a permitted wastewater treatment facility. The CWA authorizes EPA to establish pretreatment standards for pollutants that pass through or interfere with the operation of POTWs. The General Pretreatment Regulations (GPR), which set for the framework for the implementation of categorical pretreatment standards, are found at 40 CFR part 403. The GPR prohibit a user from introducing a pollutant into a POTW which causes pass through or interference. 40 CFR 403.5(a)(1). More specifically, the GPR also prohibit the introduction into of POTW of "petroleum, oil, nonbiodegradable cutting oil, or products of mineral oil origin in amounts that will cause interference or pass through.

40 CFR 403.5(b)(6). EPA believes that the GPR and the more specific categorical pretreatment standards, some of which allow indirect dischargers to adopt a BMP as an alternative way to meet pretreatment standards, will work to prevent the discharge of oil from wastewater treatment systems into navigable waters or adjoining shorelines by way of a POTW.

However, if a wastewater facility or part thereof is used for the purpose of storing oil, then there is no exemption, and its capacity must be counted as part of the storage capacity of the facility. Any oil storage capacity associated with or incidental to these wastewater treatment facilities or parts thereof continues to be subject to part 112. At permitted wastewater treatment facilities, storage capacity includes bulk storage containers, hydraulic equipment associated with the treatment process, containers used to store oil which feed an emergency generator associated with wastewater treatment, and slop tanks or other containers used to store oil resulting from treatment. Some flow through treatment such as oil/water separators have a storage capacity within the treatment unit itself. This storage capacity is subject to the rule. An example of a wastewater treatment unit that functions as storage is a treatment unit that accumulates oil and performs no further treatment, such as a bulk storage container used to separate oil and water mixtures, in which oil is stored in the container after removal of the water in the separation/treatment process.

We do not consider wastewater treatment facilities or parts thereof at an oil production, oil recovery, or oil recycling facility to be wastewater treatment for purposes of this paragraph. These facilities generally lack NPDES or state-equivalent permits and thus lack the protections that such permits provide. Production facilities are normally unmanned and therefore lack constant human oversight and inspection. Produced water generated by the production process normally contains saline water as a contaminant in the oil, which might aggravate environmental conditions in addition to the toxicity of the oil in the case of a discharge.

Additionally, the goal of an oil production, oil recovery, or oil recycling facility is to maximize the production or recovery of oil, while eliminating impurities in the oil, including water, whereas the goal of a wastewater treatment facility is to purify water. Neither an oil production facility, nor an oil recovery or oil recycling facility treats water, instead they treat oil. For purposes of this exemption, produced water is not considered wastewater and treatment of produced water is not considered wastewater treatment. Therefore, a facility which stores, treats, or otherwise uses produced water remains subject to the rule. At oil drilling, oil production, oil recycling, or oil recovery facilities, treatment units subject to the rule include open oil pits or ponds associated with oil production operations, oil/water separators (gun barrels), and heater/treater units. Open oil pits or ponds function as another form of bulk storage container and are not used for wastewater treatment. Open oil pits or ponds also pose numerous environmental risks to birds and other wildlife.

Examples of wastewater treatment facilities or parts thereof used to meet a part 112 requirement include an oil/water separator used to meet any SPCC requirement.

Oil/water separators used to meet SPCC requirements include oil/water separators used as general facility secondary containment (i.e., §112.7(c), secondary containment requirements for loading and unloading (i.e., §112.7(h)), and for facility drainage (i.e., §112.8(b) or §112.9(b)).

Whether a wastewater treatment facility or part thereof is used exclusively for wastewater treatment (i.e., not storage or other use of oil) or used to satisfy a requirement of part 112 will often be a facility specific determination based on the activity associated with the facility or part thereof. Only the portion of the facility (except at an oil production, oil recovery, or oil recycling facility) used exclusively for wastewater treatment and not used to meet any part 112 requirement is exempt from part 112. Storage or use of oil at such a facility will continue to be subject to part 112.

Although we exempt wastewater treatment facilities or parts thereof from the rule under certain circumstances, a mixture of wastewater and oil still is "oil" under the statutory and regulatory definition of the term (33 USC 1321(a)(1) and 40 CFR 110.2 and 112.2). Thus, while we are excluding from the scope of the rule certain wastewater treatment facilities or parts thereof, a discharge of wastewater containing oil to navigable waters or adjoining shorelines in a "harmful quantity" (40 CFR Part 110) is prohibited. Thus, to avoid such discharges, we would expect owners or operators to comply with the applicable permitting requirements, including best management practices and operation and maintenance provisions.

USTs. We agree that completely buried tanks that are subject to all of the technical requirements of 40 CFR part 280 or a State program approved under 40 CFR part 281 should be exempted from part 112, and have taken that action. See section V.C of this document.

Vaulted tanks. We also disagree that we should exempt aboveground, vaulted tanks from part 112. Vaulted tanks are generally excluded from the scope of 40 CFR part 280. The definition of "underground storage tank" at 40 CFR 280.12(i) excludes from its scope a "storage tank situated in an underground area (such as a basement, cellar, mineworking, drift, shaft, or tunnel) if the storage tank is situated upon or above the surface of the floor." These tanks might reasonably experience a discharge as described in §112.1(b). Therefore, it is reasonable that they be within the scope of part 112. Merely because these tanks are the subject of local fire and safety regulations does not guarantee that there will be adequate environmental protection to prevent a discharge as described in §112.1(b), because that is not the purpose of those regulations. Such codes may provide lesser protection than part 112. For example, NFPA 30:2-3.4.3(b) specifically indicates that a dike need only provide containment for the largest tank, while part 112 requires freeboard for precipitation.

Volume, not capacity. We also disagree that we should base the regulation on the amount of oil actually stored in the tanks. In most instances the shell capacity of a container will define its storage capacity. The shell capacity (or nominal or gross capacity) is the amount of oil that a container is designed to hold. If a certain portion of

a container is incapable of storing oil because of its integral design, for example electrical equipment or other interior component might take up space, then the shell capacity of the container is reduced to the volume the container might hold. When the integral design of a container has been altered by actions such as drilling a hole in the side of the container so that it cannot hold oil above that point, shell capacity remains the measure of storage capacity because such alteration can be altered again at will to restore the former storage capacity. When the alteration is an action such as the installation of a double bottom or new floor to the container, the integral design of the container has changed, and may result in a reduction in shell capacity. We disagree that operating volume should be the measurement, because the operating volume of a tank can be changed at will to below its shell capacity.

The key to the definition of “storage capacity” is the availability of the container for drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil; whether it is available for one of those uses or whether it is permanently closed. Containers available for one of the above described uses count towards storage capacity, those not used for these activities do not.

IV-E(1)-2 Other comments

Comments: *Scope of rule.* “EPA has misinterpreted its authority under section 311(j)(1) and has exceeded its jurisdiction in both existing and proposed regulations. Section 311(j)(1)(C) provides authority to require spill prevention and containment equipment rather than authority to regulate facilities.” (32, 42) We should clarify whether proposed §112.1(b)(2) and §112.1(b)(3) expanded the “scope of covered facilities” beyond those described in §112.1(b)(1). We should insert “described in subparagraph (1)” after “facilities” in subparagraphs (2) and (3). (L24)

Automotive businesses. We should exclude from part 112, automotive businesses with a total aboveground storage volume of new or used oil in quantities of 10,000 gallons or less, and aboveground tanks with a volume of 2,500 gallons or less. However, we should still require owners or operators to provide adequate secondary containment for the tanks, report releases to the EPA Administrator, and cleanup releases within 72 hours. (71)

Mobile containers.

Inclusion. We should include mobile and portable container capacity within this calculation. (L11)

Exclusion. We should exclude the capacity of mobile or portable containers of oil from a facility’s total aboveground storage capacity determination. (33, 89)

Production facilities, large or small. We should modify the proposed requirements to recognize that a small production facility presents little actual threat of a spill (based on history and amount of oil present). (28) We could inadvertently cover some facilities not currently covered by the SPCC rule. The commenter explained that some

production locations may have total storage capacity which exceeds the volume of fluid ever stored in the tanks. (86) We should exclude production tanks because aboveground tanks associated with producing oil and gas wells are small, remotely located and generally constructed to API Production Standards. (167) Interprets a statement in the preamble to mean that small and large facility classifications would not apply to oil production facilities. Asks whether this assumption is true. (L15)

Reasonable expectation of discharge. Many SPCC-regulated facilities are not located near a permanent surface water body, so an accidental discharge from them will rarely reach surface waters. (75, 79) We should obtain data and provide specific parameters to determine whether an accidental discharge could “reasonably be expected” to reach navigable waters. (75)

Can industry. We should reconsider the scope of the program for the can-making industry, already governed by many spill-prevention and accidental release regulations. (62)

Response: *Scope of rule.* Proposed §112.1(b)(2) and (3) (§112.1(b)(3) and (4) in the final rule) do not expand the applicability of the rule beyond facilities described in proposed §112.1(b)(1). In response to the commenter’s suggestion, we have revised §112.1(b) to list the types of containers that may be subject to the rule. We note, in response to comment, that we do not regulate *all* facilities in the United States. We only regulate facilities storing or using oil over the regulatory threshold amount from which there is a reasonable possibility of a discharge as described in §112.1(b). CWA section 311(j)(1)(C) authorizes EPA to establish procedures, methods, and equipment, and other requirements for equipment to prevent and contain discharges of oil from onshore facilities. This rule establishes such procedures, methods, and in some cases equipment or other requirements for equipment to prevent and contain discharges from facilities and, thus, is consistent with that authority.

Automotive businesses. We disagree that we should exclude from part 112, automotive businesses with a total aboveground storage volume of new or used oil in quantities of 10,000 gallons or less, and aboveground tanks with a volume of 2,500 gallons or less whether we required the owner or operator to provide adequate secondary containment for the tanks, report releases to the EPA Administrator, and cleanup releases within 72 hours or not. Such facilities could be the source of a discharge as described in §112.1(b) and must therefore be regulated.

Mobile containers. We disagree that we should exclude the capacity of mobile or portable containers of oil from a facility’s total aboveground storage capacity determination. A mobile facility could be the source of a discharge as described in §112.1(b) and must therefore be regulated.

Production facilities, large or small. We do not differentiate in the rule between large and small facilities because the possibility of a discharge as described in §112.1(b) is the same for both. Therefore, any facility with the requisite storage or use capacity,

whether a small or large production facility, is subject to part 112. We note that shell capacity is the measure of capacity. See the discussion concerning shell capacity in section IV-E(1)-1 of this document.

Reasonable expectation of discharge. We disagree that we could or should set specific parameters to determine whether an accidental discharge could reasonably be expected to reach protected areas. Such a determination is dependent upon facility-specific and location-specific factors.

Can industry. The can-making industry may store or use oil. If a can industry facility may reasonably be expected to discharge oil as described in §112.1(b) and has the requisite storage or use capacity, it is subject to the rule. However, an owner or operator of an SPCC facility may use an alternative plan as a substitute for an SPCC Plan if such plan meets all applicable part 112 requirements and is cross-referenced to such requirements. An owner or operator also may supplement an alternative plan that does not meet all part 112 provisions with sections that do meet part 112.

IV - E(2): Applicability - Electrical and other oil-filled equipment

Background: In the 1991 preamble, we noted that certain facilities may have equipment, such as electrical transformers, that contains significant quantities of oil necessary for operational purposes. We also clarified that an owner or operator must consider the oil storage capacity of oil-filled equipment when determining total storage capacity for subjection to SPCC regulation. Equipment use for operational purposes is not subject to the bulk storage container provisions, such as §§112.8(c) and 112.9(d). However, such equipment is subject to other applicable SPCC requirements, including the general requirements in §112.7.

Comments: *Authority.*

No CWA authority. “To be consistent with legislative intent, the Agency should make clear that the SPCC requirements do not apply to electrical equipment and to other devices that use oil operationally.” (3, 66, 92, 98, 100, 104, 125, 132, 134, 138, 156, 162, 163, 164, 170, 175, 184, 189, L2, L6, L7, L14, L16, L20)

Rule activities - storage or use of oil. We should clarify whether oil-filled equipment, such as transformers and oil breakers, are *oil storage tanks*. (66) Because “electrical equipment does not ‘consume’ oil or oil products,” and because none of the other activities listed are relevant to electrical equipment in the applicability section, the rule does not apply to it. Activities listed in the §112.1(b)(1) applicability criteria involve oil movement from one storage vessel to another, whereas dielectric fluid remains stationary and does not pose a risk to the environment. (125, 189) We should add a §112.1(d)(5) to specifically exclude from the SPCC rule, equipment or machinery containing oil for operational use rather than storage. (138) Asks us to confirm that facilities with oil-filled electrical equipment are *not* engaged in the §112.1(b) activities and are

not subject to SPCC requirements. (184) We should exclude oil-filled equipment from the SPCC regulations. We should expand the examples of equipment (that contain significant quantities of oil for operational purposes rather than storage purposes) identified in the preamble to include transformers, capacitors, and other manufacturing equipment such as small lube oil systems, fat traps, and oil-water separators. (L6)

Facility definition. Substations and other installations containing electrical equipment are not *facilities* as defined in proposed §112.2(f). Electrical equipment does not fall under §112.1(b)(1) since this section applies to *facilities* that consume oil, and the proposed §112.2(f) definition does not include units that *consume* oil. (125, 189) We should base our §112.1(b) applicability criteria on the proposed §112.2(f) *facility* definition so that the rule applies to oil well drilling operations, oil production, oil refining, oil storage, and waste treatment only. (189)

UST rules. The Underground Storage Tank (UST) program (part 280) excludes equipment or machinery containing regulated substances (i.e., oil or dielectric fluid) for operational purposes, such as hydraulic lift tanks and electrical equipment tanks. (170, 189)

Bulk storage. We should not consider electrical equipment as bulk storage containers and that proposed §§112.8(c) and 112.9(d) should not apply to such equipment. (41, 170, 164, 184) We should specifically state in the rule – not the preamble – that electrical equipment is not a *bulk tank* under the SPCC rule. (175) Products used in electrical equipment are distinct from oils stored in bulk storage tanks. (184)

Whose storage capacity? Frequently, the power company – not the facility owner or operator – owns the transformer. In such a case, must the owner or operator must include the equipment's oil capacity in determining applicability? (39)

Risk. “First, electrical equipment poses substantially less risk to the environment than do tanks, and second, many tank requirements are simply inappropriate for electrical equipment.” (39, 41, 66, 125, 164, 170) Electrical equipment poses no sufficient environmental risk because of stringent design, construction, and inspection standards. (184, 189)

Cable systems. “The Agency should exclude underground electric cable systems from SPCC requirements, regardless of the Agency's position on other types of electrical equipment.... The technology simply does not exist currently to apply the secondary containment, inspection, and integrity testing requirements of the SPCC program to underground cable systems.” (125) We should exclude electric cable systems from the rule, since such systems include tanks and reservoirs for back-up oil and are surrounded by dielectric fluids. We should recognize that electric utility facilities include features that serve operational functions and reduce risks associated with potential discharges. If

we do not exclude electric cable systems from SPCC requirements, then we should require owners or operators to prepare contingency plans, but should delete the proposed requirement to submit contingency plans when containment or diversion is not feasible. (175) We should exclude electrical equipment from the SPCC program or tailor the program to reflect specific electrical equipment characteristics. Due to the location, size, and nature of underground cable systems that extend many miles under urban streets, it is impossible for such systems to comply with SPCC tank requirements. SPCC requirements cannot be applied to dielectric fluid-filled cable systems because the design, construction, and operation of such systems differ from tank systems. (125, 189)

Response: *Authority, use of oil.* We disagree that operational equipment is not subject to the SPCC rule. We have amended §112.1(b) to clarify that using oil, for example operationally, may subject a facility to SPCC jurisdiction as long as the other applicability criteria apply, for example, oil storage capacity, or location. Such a facility might reasonably be expected to discharge oil as described in §112.1(b). Therefore, the prevention of discharges from such facility falls within the scope of the statute. However, we have distinguished the bulk storage of oil from the operational use of oil. We define “bulk storage container” in the final rule to mean any container used to store oil. The storage of oil may be prior to use, while being used, or prior to further distribution in commerce. For clarity, we have specifically excluded oil-filled electrical, -- operating, or manufacturing equipment from the “bulk storage container” definition.

Facilities that use oil operationally include electrical substations, facilities containing electrical transformers, and certain hydraulic or manufacturing equipment. The requirements for bulk storage containers may not always apply to these facilities since the primary purpose of this equipment is not the storage of oil in bulk. Facilities with equipment containing oil for ancillary purposes are not required to provide the secondary containment required for bulk storage facilities (§112.8(c)) and onshore production facilities (§112.9(c)), nor implement the other provisions of §112.8(c) or §112.9(c). Oil-filled equipment must meet other SPCC requirements, for example, the general requirements of this part, including §112.7(c), to provide appropriate containment and/or diversionary structures to prevent discharged oil from reaching a navigable watercourse. The general requirement for secondary containment, which can be provided by various means including drainage systems, spill diversion ponds, etc., will provide for safety and also the needs of section 311(j)(1)(C) of the CWA. EPA will continue to evaluate whether the general secondary containment requirements found in §112.7(c) should be modified for small electrical and other types of equipment which use oil for operating purposes. We intend to publish a notice asking for additional data and comment on this issue.

In addition, a facility may deviate from any inappropriate SPCC requirements if the owner or operator explains his reasons for nonconformance and provides equivalent environmental protection by some other means. See §112.7(a)(2). See also §112.7(d).

Facility definition. We disagree that our authority does not extend to facilities. Section 311(j)(1)(C) of the statute authorizes and requires the President (and EPA, through delegation in Executive Order 12777, 56 FR 54757, October 22, 1991) to issue regulations consistent with the National Oil and Hazardous Substances Pollution Contingency Plan, and consistent with maritime safety and with marine and navigation laws, which establish “procedures, methods, and equipment and other requirements for equipment to prevent discharges of oil and hazardous substances from vessels and from onshore and offshore facilities, and to contain such discharges.” This language authorizes the President to issue oil spill prevention rules which pertain to onshore facilities and offshore facilities and not just “equipment.”

In order to fulfill the statutory mandate, it is necessary to regulate the facilities from which discharges emanate. Moreover, although the term “facility” is not defined in the statute, both “onshore facility” and “offshore facility” are defined terms in CWA section 311. They have also been defined terms in the SPCC rule since its inception in 1974. In the 1991 proposal, EPA proposed a definition of “facility” to implement the CWA. That definition was based on a Memorandum of Understanding (MOU) between the Secretary of Transportation and the EPA Administrator dated November 24, 1971 (36 FR 24080). The MOU, which has been published as Appendix A to part 112 since December 11, 1973 (38 FR 34164, 34170), defines in detail what constitutes a facility. Thus, there has long been a common understanding of the term. That understanding has been reinforced by frequent use of the term in context within the SPCC rule since it became effective in 1974. To promote clarity and to maintain all definitions in one place, the proposed definition has been finalized in this rulemaking.

While section 311(j)(1)(C) of the Act may not explicitly mention jurisdictional criteria, section 311(b) of the Act does. Section 311(b) establishes as the policy of the United States that there shall be “no discharges of oil or hazardous substances into or upon the navigable waters of the United States, adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or which may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act).” Thus, the location or “jurisdictional” criteria contained in §112.1(b) are appropriate for inclusion in the rule.

UST rules. The two programs (SPCC and UST) have different purposes. Therefore, the rules differ in important aspects. Operational equipment is included under the SPCC rules because such equipment may experience a discharge as described in §112.1(b).

Bulk storage. We agree and clarify in today’s rule that oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container. See the discussion on the

applicability of the rule to electrical and other operating equipment under §112.1(b) in today's preamble and this section. See also the definition of "bulk storage container" in §112.2. For a discussion of minimum size containers to which the rule applies, see the discussion under §112.1(d)(2)(ii) in today's preamble and in section V.G of this document.

Regulatory threshold, storage capacity. Oil stored in operating equipment counts as storage capacity for purposes of determining whether the facility meets the regulatory threshold of greater than 1,320 gallons for aboveground containers. Such equipment or machinery might reasonably be expected to discharge oil as described in §112.1(b). Aggregate capacity is important even if the equipment is not hydraulically interconnected because if a catastrophic event were to occur, all of the equipment might fail at once and discharge oil. The key to the definition of *storage capacity* is the availability of the container for drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil; whether it is available for one of those uses or whether it is permanently closed. Containers available for one of the above described uses count towards storage capacity, those not used for these activities do not. Types of containers counted as storage capacity would include flow-through separators, tanks used for "emergency" storage, transformers, and other oil-filled equipment.

In response to the comment that the power company – not the facility owner or operator – frequently owns the transformers located at the facility, we note that the SPCC regulations generally prescribe requirements for the *owner or operator* of a facility. Either or both may be responsible for part 112 compliance.

Risk. We also disagree that electrical equipment poses no environmental risk because of stringent design, construction, and inspection standards. Such standards are not necessarily aimed at preventing discharges as described in §112.1(b), and a facility containing such equipment might reasonably be expected to experience a discharge. Therefore, it may fall within the scope of the statute.

Specific rules. We agree that differentiated rules may be warranted for facilities using electrical or other oil-filled operating equipment. In 1995, Congress enacted the Edible Oil Regulatory Reform Act (EORRA), 33 U.S.C. 2720. That statute mandates that most Federal agencies differentiate between and establish separate classes for various types of oils, specifically: animal fats and oils and greases, and fish and marine mammal oils; oils of vegetable origin; petroleum oils, and other non-petroleum oils and greases. In differentiating between these classes of oils, Federal agencies are directed to consider differences in the physical, chemical, biological, and other properties, and in the environmental effects, of the classes. In response to EORRA, as noted above, we have divided the requirements of the rule by subparts for facilities storing or using the various classes of oils listed in that act.

Because at the present time EPA has not proposed differentiated SPCC requirements for public notice and comment, the requirements for facilities storing or using all classes

of oil will remain the same. However, we have published an advance notice of proposed rulemaking seeking comments on how we might differentiate among the requirements for the facilities storing or using various classes of oil. 64 FR 17227, April 8, 1999. If after considering these comments, there is adequate justification for differentiation among the requirements for those facilities, including facilities with electrical or other oil-filled operating equipment, we will propose rule changes.

Deviations are available when a requirement is not appropriate for a particular kind of facility. See categories X-B and E of this document, and §112.7(a)(2) and (d).

IV-E(3): Minimum container size - §112.1(d)(2) and (5)

Background: Under §112.1(d)(2) of the current rule, all size containers are counted in determining the storage capacity of the facility. In 1991, we proposed no changes in the size of a container which must be counted.

Comments: *Exclude small containers.* “As written, this captures pints, quarts, equipment reservoirs of any size, once a facility determined that it was covered under this regulation.” “Clearly, compliance with these requirements for all containers of any size will be extremely burdensome for some of the regulated community and will greatly upset ongoing manufacturing operations, while providing no significant increase in protection of human health and the environment.” (33, 62, 66, 115, 119, 127, 175, 190, L7)

Suggested thresholds for minimum size- aboveground storage.

250 gallons or less. (62).

55 gallons or less. (29, 57, 103, 119, L24)

660 gallons or less. (22, 48, 67, 91, 92, 98, 106, 125, 133, 150, 167, 182, 187, L14)

10,000 gallons. (170)

25,000 gallons. (189)

Response: *Minimum container size.* In response to comments, we are introducing a minimum container size to use for calculation of the capacity of aboveground storage tanks and completely buried containers. Therefore, you need only count containers of 55 gallons or greater in the calculation of the regulatory threshold for storage capacity. You need not count containers, like pints, quarts, and small pails, which have a storage capacity of less than 55 gallons, in capacity calculations. Some SPCC facilities might therefore drop out of the regulated universe of facilities. You should note, however, that EPA retains authority to require any facility subject to its jurisdiction under section 311(j)

of the CWA to prepare and implement an SPCC Plan, or applicable part, to carry out the purposes of the Act.

While some commenters had suggested a higher threshold level, we believe that inclusion of containers of 55 gallons or greater within the calculation for the regulatory threshold is necessary to ensure environmental protection. If we finalized a higher minimum size, the result in some cases would be large amounts of aggregate capacity that would not be counted for SPCC purposes, and would therefore be unregulated, posing a threat to the environment. We believe that it is not necessary to apply SPCC or FRP rules requiring measures like secondary containment, inspections, or integrity testing, to containers smaller than 55 gallons storing oil because a discharge from these containers generally poses a smaller risk to the environment. Furthermore, compliance with the rules for these containers could be extremely burdensome for an owner or operator and could upset manufacturing operations, while providing little or no significant increase in protection of human health or the environment. Many of these smaller containers are constantly being emptied, replaced, and relocated so that serious corrosion will likely soon be detected and undetected leaks become highly unlikely. While we realize that small discharges may harm the environment, depending on where and when the discharge occurs, we believe that this measure will allow facilities to concentrate on the prevention and containment of discharges of oil from those sources most likely to present a more significant risk to human health and the environment.

IV - G Wastewater Treatment - §112.1(d)(6).

Background: In 1991, EPA proposed various changes to §112.1(d) concerning exemptions to part 112, and received comments on its proposals. Among those comments was one suggesting an exemption for certain treatment systems.

Comments: One commenter suggested that the “§112.1 exceptions should be expanded to include facility storage and treatment tanks associated with ‘non-contact cooling water systems’ and/or ‘storm water retention and treatment systems. Although these tanks are designed to remove spilled oil from manufacturing operations and parking lot runoff, the concentration of oil in the water at any given time would be insignificant. These tanks are typically very large, i.e., in excess of 100,000 gallons, and are typically not contained by diked walls or impervious surfaces. GM believes the cost to contain these structures could be better spent on other SPCC regulatory requirements.”

Response: We agree with the commenter that certain wastewater treatment facilities or parts thereof should be exempted from the rule, if used exclusively for wastewater treatment and not used to meet any other requirement of part 112. We have therefore amended the rule to reflect that agreement. No longer subject to the rule would be wastewater treatment facilities or parts thereof such as treatment systems at POTWs and industrial facilities treating oily wastewater.

Many of these wastewater treatment facilities or parts thereof are subject to NPDES or state-equivalent permitting requirements that involve operating and maintaining the facility to prevent discharges. 40 CFR 122.41(e). The NPDES or state-equivalent process ensures review and approval of the facility's: plans and specifications; operation/maintenance manuals and procedures; and, Stormwater Pollution Prevention Plans, which may include Best Management Practice Plans (BMP).

Many affected facilities are subject to a BMP prepared under an NPDES permit. Some of those plans provide protections equivalent to SPCC Plans. BMPs are additional conditions which may supplement effluent limitations in NPDES permits. Under section 402(a)(1) of the CWA, BMPs may be imposed when the Administrator determines that such conditions are necessary to carry out the provisions of the Act. See 40 CFR 122.44(k). CWA section 304(e) authorizes EPA to promulgate BMPs as effluent limitations guidelines. NPDES rules provide for BMPs when: authorized under section 304(e) of the CWA for the control of toxic pollutants and hazardous substances; numeric limitations are infeasible; or, the practices are reasonably necessary to achieve effluent limitations and standards to carry out the purposes of the CWA. In addition, each NPDES or state equivalent permit for a wastewater treatment system must contain operation and maintenance requirements to reduce the risk of discharges. 40 CFR 122.41(e).

Additionally, some wastewater is pretreated prior to discharge to a permitted wastewater treatment facility. The CWA authorizes EPA to establish pretreatment standards for pollutants that pass through or interfere with the operation of POTWs. The General Pretreatment Regulations (GPR), which set the framework for the implementation of categorical pretreatment standards, are found at 40 CFR part 403. The GPR prohibit a user from introducing a pollutant into a POTW which causes pass through or interference. 40 CFR 403.5(a)(1). More specifically, the GPR also prohibit the introduction into of POTW of "petroleum, oil, nonbiodegradable cutting oil, or products of mineral oil origin in amounts that will cause interference or pass through. 40 CFR 403.5(b)(6). EPA believes that the GPR and the more specific categorical pretreatment standards, some of which allow indirect dischargers to adopt a BMP as an alternative way to meet pretreatment standards, will work to prevent the discharge of oil from wastewater treatment systems into navigable waters or adjoining shorelines by way of a POTW.

However, if a wastewater facility or part thereof is used for the purpose of storing oil, then there is no exemption, and its capacity must be counted as part of the storage capacity of the facility. Any oil storage capacity associated with or incidental to these wastewater treatment facilities or parts thereof continues to be subject to part 112. At permitted wastewater treatment facilities, storage capacity includes bulk storage containers, hydraulic equipment associated with the treatment process, containers used to store oil which feed an emergency generator associated with wastewater treatment, and slop tanks or other containers used to store oil resulting from treatment. Some flow through treatment such as oil/water separators have a storage capacity within the treatment unit itself. This storage capacity is subject to the rule. An example of a wastewater treatment unit that functions as storage is a treatment unit that accumulates

oil and performs no further treatment, such as a bulk storage container used to separate oil and water mixtures, in which oil is stored in the container after removal of the water in the separation/treatment process.

We do not consider wastewater treatment facilities or parts thereof at an oil production, oil recovery, or oil recycling facility to be wastewater treatment for purposes of this paragraph. These facilities generally lack NPDES or state-equivalent permits and thus lack the protections that such permits provide. Production facilities are normally unmanned and therefore lack constant human oversight and inspection. Produced water generated by the production process normally contains saline water as a contaminant in the oil, which might aggravate environmental conditions in addition to the toxicity of the oil in the case of a discharge.

Additionally, the goal of an oil production, oil recovery, or oil recycling facility is to maximize the production or recovery of oil, while eliminating impurities in the oil, including water, whereas the goal of a wastewater treatment facility is to purify water. Neither an oil production facility, nor an oil recovery or oil recycling facility treats water, instead they treat oil. For purposes of this exemption, produced water is not considered wastewater and treatment of produced water is not considered wastewater treatment. Therefore, a facility which stores, treats, or otherwise uses produced water remains subject to the rule. At oil drilling, oil production, oil recycling, or oil recovery facilities, treatment units subject to the rule include open oil pits or ponds associated with oil production operations, oil/water separators (gun barrels), and heater/treater units. Open oil pits or ponds function as another form of bulk storage container and are not used for wastewater treatment. Open oil pits or ponds also pose numerous environmental risks to birds and other wildlife.

Examples of wastewater treatment facilities or parts thereof used to meet a part 112 requirement include an oil/water separator used to meet any SPCC requirement. Oil/water separators used to meet SPCC requirements include oil/water separators used as general facility secondary containment (i.e., §112.7(c), secondary containment requirements for loading and unloading (i.e., §112.7(h)), and for facility drainage (i.e., §112.8(b) or §112.9(b)).

Whether a wastewater treatment facility or part thereof is used exclusively for wastewater treatment (i.e., not storage or other use of oil) or used to satisfy a requirement of part 112 will often be a facility specific determination based on the activity associated with the facility or part thereof. Only the portion of the facility (except at an oil production, oil recovery, or oil recycling facility) used exclusively for wastewater treatment and not used to meet any part 112 requirement is exempt from part 112. Storage or use of oil at such a facility will continue to be subject to part 112.

Although we exempt wastewater treatment facilities or parts thereof from the rule under certain circumstances, a mixture of wastewater and oil still is "oil" under the statutory and regulatory definition of the term (33 USC 1321(a)(1) and 40 CFR 110.2 and 112.2). Thus, while we are excluding from the scope of the rule certain wastewater treatment

facilities or parts thereof, a discharge of wastewater containing oil to navigable waters or adjoining shorelines in a "harmful quantity" (40 CFR Part 110) is prohibited. Thus, to avoid such discharges, we would expect owners or operators to comply with the applicable permitting requirements, including best management practices and operation and maintenance provisions.

Category V: Definitions - §112.2

Background: In §112.2 of the current rule are found definitions for terms used in 40 CFR part 112. In §112.2 of the 1991, we proposed revisions of certain definitions, adding some new definitions, and removing others. We also proposed to move the definitions of *oil production facilities (onshore)* and *oil drilling, production, or workover facilities (offshore)* from §112.7(e)(5)(i) and 112.7(e)(7)(i), respectively, to §112.2.

V- 1 *Breakout tank*

Background: In §112.2(a) of the 1991 proposal, we proposed to define *breakout tank* to distinguish between facilities regulated by the U.S. Department of Transportation (DOT) and EPA. (Breakout tanks fall under DOT jurisdiction; we regulate facilities with bulk storage tanks.) *Breakout tanks* are used either to compensate for pressure surges or control and maintain pressure through pipelines. In §112.2 of the final rule, we adopted a modified version of DOT's 49 CFR part 195 definition, and defined a *breakout tank* as "a container used to relieve surges in an oil pipeline system or to receive and store oil transported by a pipeline for reinjection and continued transportation by pipeline."

Comments: *Support for a definition.* Support for including a definition of *breakout tank* in part 112. (94, 95, 102)

DOT definition. "Valvoline supports the inclusion of a definition of 'breakout tank' in the proposed regulations. However, in light of the fact that this is a transportation-related term, the definition should be identical to that contained in 40 CFR §195.2. An arbitrary change to this definition will result in wide spread confusion regarding what constitutes a breakout tank and which definition takes precedence." (77, 95, 101, 102, 113, 121, 153, 173, 175) We should consider providing guidance on when each agency regulates certain tanks. (94) Two different definitions would result in duplicative regulation of certain tanks. (102, 153)

Response: On the suggestion of commenters, EPA has adopted a modified version of the DOT definition in 49 CFR 195.2. This revision promotes consistency in the DOT and EPA definitions to aid the regulators and regulated community. We modified the DOT definition by substituting the word "oil" for "hazardous liquid," because our rules apply only to oil. We also use in the definition the term "container" rather than just "tank" to cover any type of container. This terminology is consistent with other terminology used in this rule.

A breakout tank that is used only to relieve surges in an oil pipeline system or to receive and store oil transported by a pipeline for reinjection and continued transportation by pipeline is subject only to DOT jurisdiction. When that same breakout tank is used for other purposes, such as a process tank or as a bulk storage container, it is no longer solely within the definition of breakout tank, and may be subject to EPA or other jurisdiction with the new use. See also the discussion of §112.1(d)(1)(ii) in the

preamble to today's rule. EPA and DOT also signed a joint memorandum dated February 4, 2000, clarifying regulatory jurisdiction on breakout tanks. That memorandum is available to the public upon request. It is also available on our website at <http://www.epa.gov/oilspill> under the "What's New" section.

V- 2 *Bulk storage container*

Background: In 1991, we proposed defining the term *bulk storage tank* to clarify the distinction between facilities regulated by DOT and EPA. The proposed definition was originally for "bulk storage tank."

Comments: We should exclude electrical equipment from the *bulk storage tank* definition because such equipment does not consume or store oil. (41, 125, 134, 164)

Response: We agree that electrical equipment is not bulk storage, and have revised the definition of *bulk storage container* to specifically exclude oil-filled electrical, operating, or manufacturing equipment. While such equipment is not bulk storage, it is subject to the general requirements of the rule in §112.7.

V - 3 *Bunkered tank*

Background: We proposed this definition in 1991 to clarify that bunkered tanks are a subset of partially buried tanks, and as such, subject to part 112 as aboveground tanks.

Comments: The definition is "undecipherable and should be rewritten." The definition should be, "Bunkered tank means a partially buried tank, the portion of which lies above grade is covered with earth, sand, gravel, asphalt, or other material." (121)

Response: EPA agrees that the commenter's proposed definition is clearer, and we have used it with a slight editorial change.

Editorial change. We added a sentence to the definition noting that bunkered tanks are a subset of aboveground storage containers for purposes of this part.

V- 4 *Completely buried tank*

Background: We proposed in §112.2(v) to define an *underground storage tank (UST)* as any tank completely covered with earth. We noted that tanks in subterranean vaults, bunkered tanks, or partially buried tanks are aboveground storage containers under part 112. We have editorially changed "underground storage tank" to "completely buried tank" to distinguish those tanks from the "underground storage tank" definition in part 280, which is broader than our definition.

Comments: *Consistency with part 280 definition.* The part 112 definition of an *UST* should be consistent with the part 280 definition. (57, 78, 90, 109, 111, 116, 167, 180, 182, 187). The differences in the definitions in parts 112 and 280 would confuse the

regulated community. (57, 90, 111) We should define an *UST* as any tank that is completely below grade, and completely covered with earth, including vaults, bunkered tanks, or partially buried tanks. (102, 121) The part 280 UST definition is more consistent with our statutory authority under the Clean Water Act (CWA) than the part 112 definition. (182) Our proposed definition is too narrow, because it includes only completely buried tanks. (67, 72, 102, 106, 133, 175, 182)

New term needed. “Alyeska appreciates that EPA requires a different definition for underground tanks than 40 CFR Part 280. However, it is very confusing for the regulated community to have two different definitions to the term ‘underground storage tank.’ EPA should identify tanks that it wishes to exclude from SPCC Plan regulations by some other term to avoid this confusion. EPA invites inadvertent non-compliance when it uses a term which has two different definitions.” (27, 77, 87)

Bunkered tanks, partially buried tanks. We should consider bunkered tanks and partially buried tanks as aboveground storage tanks under part 112. We should regulate a tank under part 112 as an aboveground tank only if it is not regulated under part 280. (190)

Vaulted tanks. “In some locations (e.g., New York City), subterranean vaults are the method of secondary containment specified for underground storage tanks. The vault and tank in such cases are usually completely covered by earth and, thus, pose no threat to the waters of the US. Such tanks should be exempted from the SPCC requirements.” (33, 67, 72, 121, 133, 175)

Response: *Support for proposal.* We appreciate commenter support.

Consistency with part 280 definition. We disagree that the scope of the part 112 exclusion for underground tanks should be consistent with the scope of the definition of “underground storage tank” in part 280. The programs are designed for different purposes, therefore, the definitions used will necessarily differ. To eliminate confusion with the part 280 definition, we have changed the proposed part 112 definition of “underground storage tank” to “completely buried tank” in this final rule.

Part 280 includes within its UST definition tanks which have a volume up to ninety percent above the surface of the ground, which are considered aboveground tanks for part 112 purposes. Part 280 also regulates underground storage tanks containing hazardous substances, while the SPCC program regulates only facilities storing or using oil as defined in CWA section 311. The SPCC program also regulates other types of containers and facilities which part 280 excludes, such as: tanks used for storing heating oil for consumptive use on the premises where stored; certain pipeline complexes where oil is stored; and, oil-water separators.

Other completely buried tanks excluded from the part 280 UST definition. Tanks in underground rooms or above the floor surface, or in other underground areas

such as basements, cellars, mine workings, drifts, shafts, or tunnels are also not considered USTs for purposes of the part 280 definition. The purpose of the part 112 definition is to clarify that these are tanks that are technically underground but that, in a practical sense, are no different from aboveground tanks. They are situated so that, to the same extent as tanks aboveground, physical inspection for leaks is possible. Also, some of these tanks are designed such that in case of a discharge, oil would escape to the environment, a result which our program seeks to prevent.

Editorial changes and clarifications. The words “completely below grade and....” were added to the first sentence of the definition. The purpose of that revision was to distinguish completely buried tanks from partially buried and bunkered tanks, which break the grade of the land, but are not completely below grade. We further clarify that such tanks may be covered not only with earth, but with sand, gravel, asphalt, or other material. The clarification brings the definition into accord with the coverings noted in the definition of “bunkered tank.” In the second sentence, the word “subterranean” was deleted from “subterranean vaults” because all vaulted tanks, whether subterranean or aboveground, are counted as aboveground tanks for purposes of this rule.

Bunkered tanks, partially buried tanks. We disagree that vaulted tanks, partially buried tanks, and bunkered tanks should be considered completely buried tanks, and therefore excluded from SPCC provisions. Such tanks may suffer damage caused by differential corrosion of buried and non-buried surfaces greater than completely buried tanks, which could cause a discharge as described in §112.1(b).

Vaulted tanks. Aboveground vaulted tanks are clearly ASTs. Subterranean vaulted tanks are also ASTs because they are not completely buried. While subterranean vaulted tanks may be completely below grade, they are not completely covered with earth, sand, gravel, asphalt, or other material. Therefore, because of their design, they pose a threat of discharge into the environment, and are excluded from our definition of completely buried tank. Subterranean vaulted tanks are also excluded from the part 280 UST definition of underground tank if the storage tank is situated upon or above the surface of the floor in an underground area providing enough space for physical inspection of the exterior of the tank. Therefore, if subterranean tanks were excluded from our definition of completely buried tank, they would likely not be regulated at all, and thereby be likely to pose a greater threat to the environment.

V- 5 Discharge

Background: In proposed §112.2(e), we suggested modification of the definition of *discharge* to reflect changes in the 1978 amendments to the CWA.

Comments: *Section 402 discharges.* We should exclude discharges regulated under CWA section 402 to eliminate duplicative regulations. (67, 125)

Imminent danger. “Recommend that the definition of discharge include that there is at least an eminent danger that the spilled material reach a ‘navigable waterway’.” Otherwise, it is too broad and would cover even spills within secondary containment.” (28, 31, 101, 113, 121, 165, L15)

Discharges within secondary containment or the facility. We should define *discharge* to include a spill, leak, or other release that reaches navigable waters. A spill or leak will not necessarily result in a discharge to navigable waters. (39, 121, L12) The proposed definition seems vague, because it is “unlikely to operationally prevent all spilling or leaking.” It is unclear, for example, whether a drop of oil that falls “onto the outside casing of a tank during refilling would be considered a *discharge*, even if the oil did not reach the ground.” The definition is inconsistent with part 112. (115) Our proposed definition appears to “regulate more than the quality of navigable waters.” (L12)

Response: *Section 402 discharges.* We agree that we should not regulate discharges under section 402 of the Act, and in the final rule, we have adopted the proposed definition of a *discharge*, which accomplishes that aim.

Foreseeable or chronic point source discharges that are permitted under section 402 of the CWA, and that are either due to causes associated with the manufacturing or other commercial activities in which the discharger is engaged or due to the operation of the treatment facilities required by the NPDES permit, are to be regulated under the NPDES program. Other oil discharges in reportable quantities are subject to the requirements of section 311 of the CWA. Such spills or discharges are governed by section 311 even where the discharger holds a valid and effective NPDES permit under CWA section 402. Therefore, a discharge of oil to a publicly-owned treatment work (POTW) would not be a discharge under the §112.2 definition if the discharge is in compliance with the provisions of the permit; or resulted from a circumstance identified and reviewed and made a part of the public record with respect to a permit issued or modified under section 402; or if it were a continuous or anticipated intermittent discharge from a point source, identified in a permit or permit application under section 402, which is caused by events occurring within the scope of relevant operating or treatment systems. 33 U.S.C. 1321(a)(2); 40 CFR 117.12. Otherwise, the discharge is subject to the provisions of section 311 of the CWA as well as the unpermitted discharge prohibition of section 301(a) of the CWA. 33 U.S.C. 1311(a).

Imminent danger. A discharge as described in §112.1(b) need not reach the level of an imminent danger to affected lands, waters, or resources to be a discharge.

Discharges within secondary containment or the facility. We agree that we should define *discharge* to include a spill, leak, or other release that reaches navigable waters, and have done so. We define a discharge to include any spilling, leaking, pumping, emitting, emptying, or dumping of oil,” with certain exclusions pertinent to section 402 of

the CWA. We also agree that a spill, leak, or other type of discharge will not necessarily result in a discharge to navigable waters. A discharge includes any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of any amount of oil no matter where it occurs. It may not be a reportable discharge under 40 CFR part 110 if oil never escapes the secondary containment at the facility and is promptly cleaned up. If the discharge escapes secondary containment, it may become a discharge as described in §112.1(b), and if that happens, the discharge must then be reported to the National Response Center.

V- 6 *Facility*

Background: In §112.2(f) of the 1991 proposal, we proposed to define the term facility based on the definition in the 1971 MOU between EPA and DOT. (See 40 CFR part 112, Appendix A.) We proposed to define a *facility* as “any mobile or fixed, onshore or offshore building, structure, installation, equipment, pipe, or pipeline used in oil well drilling operations, oil production, oil refining, oil storage, and waste treatment.” We noted that the extent of a *facility* may depend on several site-specific factors, including, but not limited to, the ownership or operation of buildings, structures, equipment, and pipelines on the same site and the types of activities at the site.

Comments: *Facility boundaries.* “The definition of *facility* are [sic] too broad. Not all buildings on an oil production lease are in contact with oil, nor are all pipeline structures, installations, or equipment. Their operation may in no way affect the possibility of an oil spill, and they should not have to be addressed in a SPCC plan as inclusion in this definition would require. The same is true for waste treatment activities.” (31, 101, 113, 160, 165, 188, L15) “The definition of *facility* is ambiguous. Is a *facility* the petroleum storage site, or ... a single tank at a site?” (111, 188)

Pipes and piping. “Rather, the definition contemplates a fixed structure, or unit, which serves a purpose at the place where it is fixed. ... We suggest that EPA clarify the factors which will, rather than may, define the boundaries of a facility, specifically with regard to piping or pipelines which may extend past the physical boundaries of the facility.” (188)

Buried pipelines, gathering lines, flowlines, military housing units, waste treatment equipment. “Also, by including oil gathering lines in the facility definition, the size and extent of oil production facilities is multiplied at least a thousand-fold. No secondary containment is possible for these lines....” (31) “Based on the proposed definition, it is unclear whether the regulation requires that all oil distribution and movement facilities be identified, such as buried pipelines, for volume storage estimates. This too presents a task which cannot readily be satisfied at many mining operations.” (35, 28, 31, 58, 71, 101, 113, 165, L15).

Military housing. We should amend the proposed definition to ensure that part 112 does not cover military housing units. Each such unit may store fuel oil in a 250-gallon tank. (L29)

Waste treatment. We should not include the term *waste treatment* in the part 112 definition of a *facility*, unless the waste treated is from oil drilling or production operations. (L24, 31)

Electrical or operational equipment. “Clearly, electrical equipment is not used in well drilling operations, oil production, oil refining, oil storage, or waste treatment. As such, oil-filled electrical equipment is not a ‘facility’ under the proposed SPCC regulations and not subject to the requirements established therein.” (189)

Mobile or fixed facilities. “CCIRT is concerned that the proposed definition is overly broad, because it encompasses mobile as well as fixed, structures and equipment. CCIRT considers this expansion of the definition to be inappropriate. ... Conceivably, a SPCC Plan for a mobile ‘facility’ would have to be amended each time the mobile equipment is moved. This is likely to be an unworkable requirement. For these reasons, mobile equipment should not be considered a facility for purposes of SPCC regulations.” (188)

Response: We disagree that the definition is too broad. It includes the necessary elements of what may be a “facility.” If one of those elements is not related to oil well drilling operations, oil production, oil refining, oil, storage, and waste treatment, or in which oil is used at the site, it is not part of the facility.

Facility boundaries. A facility includes any building, structure, installation, equipment, pipe, or pipeline in oil well drilling operations, oil production, oil refining, oil storage, and waste treatment, or in which oil is used at a site, whether it is mobile or fixed. It may also include power rights of way connected to the facility. We also clarify that a vessel or a public vessel is not a facility or part of a facility. The extent of the facility will vary according to the circumstances of the site. It may be as small as a single container, or as large as all of the structures and buildings on a site. Some specific factors to use in determining the extent of a facility may be the ownership or operation of those buildings, structures, equipment, installations, pipes or pipelines, or the types of activities being carried on at the facility.

Electrical or operational equipment. We disagree with commenters who maintained that electrical equipment “using” oil, as opposed to “storing” it, should not fall within the definition of “facility” in part 112. Section 311(j)(1)(C) of the CWA, which authorizes EPA to promulgate the SPCC rule, does not distinguish between the storage and the usage of oil. The section simply authorizes EPA, as delegated by the President, to establish “requirements to prevent discharges of oil ... from onshore and offshore facilities, and to contain such discharges...” 33 U.S.C. 1321(j)(1)(C). Nor do the definitions of “onshore facility” or “offshore facility” in sections 311(a)(10) of the CWA distinguish between the use or storage of oil. Although the definition of “facility” in section 1001(9) of the OPA is limited by the “purpose” of the facility, no such limitation appears in CWA section 311. Moreover, EPA believes that although much of the electrical equipment may arguably “use” oil, in effect the oil is “stored” in the equipment because it remains in the equipment for such long time frames. We added language to the definition to clarify

that such types of equipment are facilities subject to the SPCC rule whether they are storing or using oil. Therefore, we revised the definition to include the words “or in which oil is used.” However, we note that a facility which contains only electrical equipment is not a bulk storage facility.

Buried pipelines, gathering lines, flowlines, military housing units, waste treatment equipment. Buried pipelines that carry oil at mining sites are part of a facility unless they are permanently closed as defined in §112.2. Such pipelines may otherwise be the source of a discharge as described in §112.1(b). Likewise, the same rationale applies to gathering lines and flowlines, military housing units, and waste treatment equipment. Note that any facility or part thereof used exclusively for wastewater treatment and not to satisfy any part 112 requirement is exempted from the rule. The production, recovery, or recycling of oil is not considered wastewater treatment for purposes of the rule. See §112.1(d)(6).

While such gathering lines, flowlines, and waste treatment equipment are subject to secondary containment requirements, the appropriate method of secondary containment is an engineering question. Double-walled piping may be an option, but is not required by these rules. The owner or operator and Professional Engineer certifying the Plan should consider whether pursuant to good engineering practice, double-walled piping is the appropriate method of secondary containment according to good engineering practice. In determining whether to install double-walled piping versus an alternative method of secondary containment, you could consider such factors as the additional effectiveness of double-walled piping in preventing discharges, the technical aspects of cathodically protecting any buried double-walled piping system, the cost of installing double-walled pipe, and the potential fire and safety hazards of double-walled pipes. Earthen or natural structures may be acceptable if they contain and prevent discharges as described in §112.1(b), including containment that prevents discharge of oil through groundwater that might cause a discharge as described in §112.1(b). What is practical for one facility, however, might not work for another.

We also disagree with the argument that because the installation of structures and equipment to prevent discharges around gathering lines and flowlines may not be practicable, EPA will be flooded with contingency plans. First of all, secondary containment may be practicable. In §112.7(c), we list sorbent materials, drainage systems, and other equipment as possible forms of secondary containment systems. We realize that in many cases, secondary containment may not be practicable. If secondary containment is not practicable, you must provide a contingency plan in your SPCC Plan following the provisions of part 109, and otherwise comply with §112.7(d). We have deleted the proposed 1993 provision that would have required you to provide contingency plans as a matter of course to the Regional Administrator. Therefore, you will rarely have to submit a contingency plan to EPA. The contingency plan you do provide in your SPCC Plan when secondary containment is not practicable for flowlines and gathering lines should rely on strong maintenance, corrosion protection, testing, recordkeeping and inspection procedures to prevent and quickly detect discharges from such lines. It should also provide for the quick availability of response equipment.

Mobile or fixed facilities. Either mobile or fixed equipment might be the source of a discharge as described in §112.1(b), and therefore both are included within the definition of “facility.” Section 112.3(c) of this rule already provides that it is not necessary to amend your Plan each time a mobile facility moves to a new site.

V - 7 Navigable waters

Background: In §112.2(g) of the 1991 proposal, we proposed to revise the definition of *navigable waters* to conform to the definition in 40 CFR part 110.

Comments: *Definition too broad, clarification needed.* (31, 35, 64, 73, 89, 101, 106, 113, 165, 174, 186, L15, L23) “We have two concerns with this proposal. First, we do not believe EPA should expand its jurisdictional authority since the jurisdiction provided under traditional notions of navigability and contained in the existing regulations is sufficient to protect the Nation’s waters from bulk oil contamination. ... Second, under §404 of the Clean Water Act, EPA interprets the predicate jurisdictional trigger, ‘waters of the United States,’ in an expansive manner to include artificial and isolated wetlands.” Wetland delineation is quite complex, and often includes areas that are not adjacent to navigable waters, nor even tributary or in any connected to navigable waters.” (35) “We feel that compliance with these regulations could be more easily obtained if this definition was simplified.” (94, 111, 166) “Using this interpretation, nearly all facilities would be located less than 500 feet from navigable waters. Some guidance as to the correct interpretation of this issue would be helpful.” (107, 79, 167, 186, L17)

Navigability. “The definition of navigable waters should be revised to match what Congress originally intended - waters that a boat of some kind (even a canoe) can travel on at all times of the year.” (31, 73, 101, 106, 113, 165, L15) “Navigable Waters is defined in extremely broad terms under the proposed definition. While broad statutory references are made elsewhere in the proposed rule, no specific authority, legislative or judicial, is cited or identified to support this expansive definition.” (64)

Risk. “The EPA’s emphasis in this phase of the SPCC revisions should be on controlling discharges from facilities with the greatest potential to discharge harmful quantities of oil to navigable waters. The broad applicability of the proposed SPCC revisions will overwhelm the regulated community.” (167) “The proposed rule’s mention of discharges into or upon the navigable waters of the United States together with the extremely broad interpretation of ‘navigable waters’ and waters which flow to ‘navigable waters’ could result in application of this rule to inland agricultural operations.” (L23)

Tributaries. Asks, “...(A)re ditches which flow miles to navigable waters considered tributaries?” (62) “Since the EPA considers tributaries to navigable water (i.e., rivers) as part of this definition, ultimately any size stream, including those which may be only intermittent, would be subject to this rule.” (89) We

should define *navigable waters* as “unobstructed streams that free flow at least fourteen consecutive days per year.” (186)

Criteria. The definition should “include specific criteria such as flow volume.” (89, 156)

Maps. “Due to the broad definition of navigable waters, how is an operator to determine what is navigable water? Because this is such a confusing issue, an operator is at a loss to determine which facilities could reasonably be expected to discharge oil upon a navigable water. Will the EPA provide maps to aid in this determination?” (28, 69, 79, 101)

Groundwater. “...(C)ongress intended for EPA to develop SPCC requirements that prevent releases to groundwater, in addition to requirements that prevent releases to navigable waters. Thus, SPCC regulations should be rewritten to prevent discharges to groundwater in addition to discharges to navigable waters. ... At a minimum, proposed section 112.1(d)(1)(i) should contain language stating that clear hydrologic connections between groundwater underlying a facility and navigable waters require a facility to develop and implement an SPCC Plan.” (44)

Response: *Clarification of the meaning of navigable waters, maps.* In this definition, we clarify what we mean by navigable waters by describing the characteristics of navigable waters and by listing examples of navigable waters. We also note in the definition that certain waste treatment systems are not navigable waters.

Navigability, legal authority. Navigable waters are not only waters on which a craft may be sailed. Navigable waters include all waters with a past, present, or possible future use in interstate or foreign commerce, including all waters subject to the ebb and flow of the tide. Navigable waters also include intrastate waters which could affect interstate or foreign commerce. The case law supports a broad definition of navigable waters, such as the one published today, and that definition does not necessarily depend on navigability in fact.

Tributaries. For the reasons stated above, tributaries or intermittent streams are included in the definition of *navigable waters*, and it would therefore be inappropriate to limit the definition to unobstructed streams that free flow at least fourteen consecutive days a year.

Maps. We are unable to provide a map to identify all navigable waters because not all such waters have been identified on a map. However, the rule provides guidelines as to where such waters may be found.

Groundwater. EPA agrees with the commenter that groundwater underlying a facility that is directly connected hydrologically to navigable waters or adjoining shorelines could trigger the requirement to produce an SPCC Plan based on geographic or locational aspects of the facility.

V - 8 Offshore facility

Background: In 1991, we proposed to revise the definition of *offshore facility* to conform with the CWA definition in section 311(a)(11) and the National Oil and Hazardous Substances Pollution Contingency Plan (NCP) definition in 40 CFR 300.5.

Comments: *CWA definition.* “Offshore Facility is defined in an ambiguous and circuitous manner in the proposed rules. Midway through the proposed definition, the unnecessarily redundant phrase ‘and any facility of any kind that is subject to the jurisdiction of the United States and is located in, on, or under any other waters’ is included. The definition in the CWA is better and clearer.” (64)

EPA or DOI jurisdiction. “We note that if the definition of ‘offshore facility’ in section 1001(22) of OPA 90 is taken in context with the definition of ‘navigable waters’ proposed for 40 CFR 112.2(g), the jurisdiction for many facilities (including large numbers which have traditionally been subject to EPA jurisdiction) would be transferred to the Department of Interior (DOI) by E.O. 12777.” (128)

Response: *CWA definition.* EPA agrees with the commenter urging that the EPA definition track the statutory definition. The part 112 definition, except for minor editorial changes, is identical to the CWA definition. There is no difference between the substance of the part 112 definition and the CWA definition.

EPA or DOI jurisdiction. The 1994 Memorandum of Understanding between DOI, DOT, and EPA addresses the jurisdictional issue to which the commenter refers, transferring to EPA those non-transportation-related offshore facilities landward of the coast line.

V - 9 Oil

Background: In current §112.2 we define *oil* as “oil of any kind or in any form, including, but not limited to, petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil.” We proposed no changes in the definition in 1991. However, in the 1991 preamble, we explained this definition includes crude oil and refined petroleum products, as well as non-petroleum oils (e.g., animal and vegetable oils). We solicited comments on the appropriateness of this approach.

Comments: *Support for proposal.* (82, 121, 168, L8) “Section 311 of the CWA is unusual, in that it is the only section of the Act that has its own definition section. These definitions include one for oil. It is the same definition as the one presently appearing in part 112. There is nothing in section 311(j)(1)(C) that indicates that Congress contemplated a departure from this oil definition for prevention regulations. EPA must stick with the present definition of oil. As a matter of fact, a vegetable oil spill resulted in a significant duck kill on the upper Mississippi in the 1960's.” (121)

Opposition to proposal. Our expanded interpretation of what constitutes *oil* will subject many more facilities to the SPCC Plan preparation requirements, or compel many facility

owners or operators to revise existing Plans. It is too broad. (89, 155, 184, 189) We should present our definition for public comment. (190)

Petroleum products only. “The inclusion of refined petroleum in this interpretation includes a broad category of materials that do not necessarily fall within the original intent of Congress.... Releases from the storage of many of these chemicals and materials are currently regulated by other EPA programs, such as those found in CERCLA Section 304 and SARA Title III.” (89) “No mention is made in the Clean Water Act, 40 CFR Part 110, or the Deep Water Port Act to vegetable oil.” EPA should “(L)imit the definition of oil to petroleum-based crude oil and derivative products as intended by the Clean Water Act.” (110)

Other Federal and State rules. “PG&E believes that this definition sweeps too broadly and is inconsistent with parallel federal and state regulations which regulate the use, containment, and discharge of oil and petroleum products. .. PG&E encourages EPA to adopt the UST definition of petroleum as it applies to the preparation of SPCC plans.” (78, 111, 125, 184)

Specific substances. We should include in our definition of *oil*, examples of the materials covered under part 112. (62, 103, 156) Asks that we explicitly state the types of products regulated under part 112 so that State and local regulatory agencies do not make arbitrary and capricious interpretations. (189) “Clarification of the definition of ‘oil’ is recommended. ... Considerable confusion on the definition of oil still exists.” (190, L7)

Asphalt cement. We should clarify whether our definition includes asphalt cement and other oil-containing products that are not liquid at ambient temperature. (76)

Viscosity. “There is no provision or consideration of the potential of the stored material to spill off-site. For example, ‘petroleum’ includes lubricating materials and asphalt cement which are highly viscous and could not flow very far if a tank or valve is damaged or vandalized. The potential for harm to any person, property or the environment is extremely limited.” (125, 149)

Chemicals and solvents. We should change the definition to include “chemicals and solvents that are stored in bulk in tanks in a manner similar to oils and (that) may cause comparable water pollution problems if discharged in harmful quantities as defined under 40 CFR Part 110.” (9)

Aromatic hydrocarbons. Asks whether “aromatic hydrocarbons and/or subsequent derivatives” are considered oil. “Dow does not believe that it is EPA’s intent to regulate such materials under 40 CFR Part 112.” (L7).

Gasoline and diesel fuel. “The definition of oil should exclude gasoline and diesel fuel. The high volatility of diesel fuel and gasoline results in rapid evaporation of spilled fuel, thereby reducing the pollution potential of the substance.” (128)

Hydrophobic materials. “Are hydrophobic materials of low molecular weight and high vapor pressure exempt - they would not impact water quality (ie. [sic] tanks of propane).” (62)

Mineral oil.

Legislative intent. “The Agency should limit the definition of ‘oil’ to petroleum and petroleum refinery products and exclude mineral oils and oils with a pour point above 60 degrees Fahrenheit from that definition.” (125)

Toxicity. We should exclude dielectric fluids from part 112 because they are used operationally in electrical equipment and have “more favorable toxicity characteristics” than most petroleum refinery products. (98, 125, 184)

Mixtures.

Bilge water. “In short, bilge water is not the same as oil. Accordingly, your regulation should expressly exclude bilge water from the same stringent requirements as are imposed upon oil spillage.” (45)

Brine and other substances. “The definition of oil does not refer to substances mixed with oil. A clarification must be made as to whether the proposed rules are intending to regulate just the handling of oil or the handling of oil and oil mixed with any other substance (e.g., brine tanks)” (154)

Hazardous substances. “Are other hazardous substances potentially regulated by this statute (are) specifically exempt from SPCC requirements.” (162)

Volume, less than 10% oil. “GM believes the definition of ‘oil’ should be amended to exclude solutions of materials containing low concentrations of oil, e.g., less than 10% by volume. Oil solutions of low concentration, if released, do not pose as great of a risk to the environment, as compared to concentrated oil solutions or compounds.” (90)

Non-petroleum oils.

Include. “The definition of ‘oil’ should specifically include non-petroleum oils, such as animal and vegetable oils. These oils pose many of the same hazards in a spill situation as do the petroleum oils....” (27, 123)

Exclude. “...(N)on-petroleum based oils such as animal and vegetable fats and soils should be exempt from all oil 40 CFR 112 requirements.” (56, 162) “It would make more sense to exclude animal/vegetable oils and include petroleum products such as solvents which pose a much greater threat to the environment....” (L17, L26)

Petroleum and its derivatives.

Crude oil. We should define *crude oil* in part 112 “so that refined products such as diesel fuel and gasoline may be distinguished from unrefined crude oil.” We should define *crude oil* as “an unrefined mixture of naturally occurring hydrocarbons produced from a well that is a liquid at a standard temperature of 60 degrees Fahrenheit and 14.73 psia.” (58)

Petrochemicals.

Exclude. “For example, EPA should specify (with examples) that petrochemicals, such as xylene, are not included in the definition of ‘oil’.” (103)

Include. We should include only crude oil and refined petroleum products in our definition of *oil*. (66) Because we already regulate refined petroleum materials under other EPA programs (e.g., CERCLA Section 304, SARA Title III, RCRA Subtitles C and D), a broad definition of *oil* “will confuse industries about regulatory compliance and interdepartmental Agency responsibilities.” (89) We should include only petroleum and “petroleum refinery products.” (125, 189)

Differentiate. “The term ‘refined petroleum products’ ... needs sharpening. Not only are substances like fuel oil or diesel fuel or lubricating oils ‘refined petroleum products,’ but so are other substances which clearly are not oil-like such as ethylene/polyethelene, propylene/polypropylene, styrene/polystyrene which are ... clearly not oil-like.” (L26)

Solid and gaseous oils. “We believe that those ‘oils’ which are solids at ambient temperatures should not fall within the scope of this rulemaking. Such ‘oils’ will not pose the same kind of water pollution ‘problem’ as ‘true oils’ and should be addressed separately.” (33, 101, 102, 113)

Synthetic oils.

Exclude. “As synthetic products, such liquids do not ‘fit EPA’s definition of ‘oil’ nor are they specifically addressed under the CWA. ... EPA should, instead, specifically exempt ‘synthetic oils and similar oil-like liquids’ that do not fit its ‘definition’ of ‘oil’” (33) “Similarly, mineral oil dielectric fluids

should be excluded because they too have low toxicity and are used operationally, even though they are petroleum based.” (98, 125, 156)

Transformer oil. If we decide to change the current definition, we should add transformer oil to the list of examples. (168)

Used and waste oil. “The definition should be expanded to included [sic] used oils or the waste forms of all subject materials.” (87)

Vegetable oils, animal fats. Differences from petroleum oils.

Clarification needed. Asks us to clarify whether vegetable and mineral oils are covered under part 112. (139)

Exclude from rule. “ACMS believes that edible oils should not be governed by the OPA rulemaking.” “The EPA should consider not applying these rules to the handling and storage of animal fats and oils, particularly those which are miscible in water.” (51, 56, 137, 143)

Differences. “The physical characteristics of vegetable oils such as corn oil are so markedly different that reliance on a narrow technical reading of the term ‘oil’ is not credible.” (37, 114, 137, 156, 175) “Edible oils do not create a hydrocarbon ‘sheen’ on water surfaces as do petroleum oils. ... Edible oils are very biodegradable and present a negligible environmental threat to aquatic and animal life unless spilled in very large amounts in under unique circumstances. ... One option EPA should consider is providing needed flexibility in the SPCC rules would be to apply them as guidelines where specifically applicable to the edible oils industry.” (137, 157) “The Department believes that EPA should consider developing regulations that respond to the types of oil that may be included within a facility.” (175)

Legislative intent. “...BHP believes that the Agency is making an unreasonable extension of the definition of oil to include such substances.” (42, 56)

Risk. “Unlike petroleum products, vegetable oils: are rapidly and completely biodegradable; pose no risk to human health if spilled in drinking water sources; are not flammable; are easily handled by POTWs. The only detrimental environmental impact from a major spill of vegetable oil would be temporary oxygen depletion in surface waters and its attendant effect on fish.” (56, 137, 157).

State law (California). “We do not consider animal and vegetable oils to be subject to our oil pollution statutes. This difference is not fatal to our

regulatory process as long as the states continue to have the flexibility of planning and regulating in this area without preemption.” (193)

Risk to the environment. Our failure to distinguish between oils based on potential to cause harm to the environment subjects owners or operators to unwarranted costs. (184) We should recognize that for different types of oils, the quantity necessary to cause irreversible environmental damage is different. (L2)

Response: *Support for proposal.* We appreciate the commenters’ support. We disagree that the definition of *oil* will subject additional facilities to SPCC requirements, and currently covered facilities to additional requirements. The definition does not expand what is oil, it merely clarifies which substances are included.

Authority. We disagree that our authority only extends to petroleum-based oils. Our interpretation is consistent with Congressional intent as expressed in section 311(a)(1) of the CWA, which extends to all types of oils in any form. EPA’s definition tracks that statutory definition. Our revised definition also reflects EORRA requirements for differentiation. EORRA did not expand or contract the universe of substances that are oils, it only required differentiation, when necessary, between the requirements for facilities storing or using different types of oil.

What is oil. EPA interprets the definition of oil to include all types of oil, in whatever form, solid or liquid. That includes synthetic oils, mineral oils, vegetable oils, animal fats, petroleum derivatives, oil refuse, oil mixed with wastes other than dredged spoil, etc. We do not regulate products *similar* to oil (for examples, non-oil chemicals), but only oil under part 112. A definition based on liquidity would exclude solid oils, such as certain animal fats, a result that would be inconsistent with Congressional intent. Concerning gaseous oils, see our discussion on *Highly volatile liquids* in the preamble to today’s rule.

Specific substances.

Aromatic hydrocarbons. Aromatic hydrocarbons may or may not be oil, depending on their physical characteristics and environmental effects. Some aromatic hydrocarbons are hazardous substances.

Asphalt cement. As to certain specific substances, asphaltic cement is oil because it is a petroleum-based product and exhibits oil-like characteristics. A discharge of asphaltic cement may violate applicable water quality standards, or cause a film or sheen or discoloration of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines.

Bilge water. Bilge water that contains sufficient oil such that its discharge would violate the standards set out in 40 CFR 110.3 is considered oil. The percentage

of oil concentration in the water is not determinative for the purpose of the definition or the discharge standards.

Crude oil. We did not propose a definition of the term *crude oil* in part 112, nor do we use it, except as an example of a discharge that may occur at an onshore drilling and workover facility (see §112.10(c)). Therefore, we cannot finalize such a definition.

Highly volatile liquids. We do not consider highly volatile liquids that volatilize on contact with air or water, such as liquid natural gas, or liquid petroleum gas, to be oil. Such substances do not violate applicable water quality standards, do not cause a reportable film or sheen or discoloration upon the surface of water or adjoining shorelines, do not cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines, and are not removable. Therefore, there would be no reportable discharge as described in 40 CFR 110.3.

Mixtures. Oil means oil of any kind or in any form, including, but not limited to: fats, oils, or greases of animal, fish, or marine mammal origin; vegetable oils, including oils from seeds, nuts, fruits, or kernels; and, other oils and greases, including petroleum, fuel oil, sludge, synthetic oils, mineral oils, oil refuse, or oil mixed with wastes other than dredged spoil.

Other Federal and State rules. While our definition may differ from other Federal rules, it is necessary to implement the purposes of the CWA.

RCRA. Although releases or discharges of some refined petroleum products may be regulated under the Solid Waste Disposal Act as waste products, that program is dedicated more to waste management, and does not regulate storage of non-waste oil. The definition of petroleum in 40 CFR part 280 is a subset of the part 112 definition of “oil.” The part 112 definition of oil is broader than the part 280 definition of petroleum because part 112 regulates all types of oils, whereas part 280 regulates only petroleum.

State rules. While States may choose to regulate all oils or some oils, the CWA definition is designed to prevent the discharge of all oils.

Public comment. In response to the recommendation that we present our definition for public comment, we agree. We did so in 1991 by publishing the proposed rule in the *Federal Register*.

Risk to the environment. We disagree that in the definition of oil we should distinguish between oils by degree of risk or percentage of oil concentration. The risk or percentage of oil concentration does not change the fact that the substance is still oil and may harm the environment if discharged into it. We likewise disagree that we should distinguish between oils by degree of risk for definitional purposes. The risk does not change the fact that the substance is still oil and may harm the environment if discharged into it.

Finally, we disagree that we should exclude from the definition oil based on pour point, propensity to migrate off-site, or viscosity factors. Any oil discharged to the environment may cause harm that the rule is designed to prevent.

All oils, including animal fats and vegetable oils, can harm the environment in many ways. Oil can coat the feathers of birds, the fur of mammals and cause drowning and hypothermia and increased vulnerability to starvation and predators from lack of mobility.

Oils can act on the epithelial tissue of fish, accumulate on gills, and prevent respiration. The oil coating of surface waters can interfere with natural processes, oxygen diffusion/reaeration and photosynthesis. Organisms and algae coated with oil may settle to the bottom with suspended solids along with other oily substances that can destroy benthic organisms and interfere with spawning areas.

Oils can increase biological or chemical oxygen demand and deplete the water of oxygen sufficiently to kill fish and other aquatic organisms.

Oils can cause starvation of fish and wildlife by coating food and depleting the food supply. Animals that ingest large amounts of oil through contaminated food or preening themselves may die as a result of the ingested oil. Animals can also starve because of increased energy demands needed to maintain body temperature when they are coated with oil.

Oils can exert a direct toxic action on fish, wildlife, or their food supply. Oils can taint the flavor of fish for human consumption and cause intestinal lesions in fish from laxative properties. Tainted flavor of fish for human consumption may indicate a disease in the fish which could render them inedible and thus have a substantial impact on the fishermen who harvest them and communities who may rely on them for a food supply.

Oils can foul shorelines and beaches. Oil discharges can create rancid odors. Rancid odors may cause both health impacts and environmental impacts. For example, the 1991 Wisconsin Butter Fire and Spill resulted in a discharge of melted butter and lard. After the cleanup was largely completed, the Wisconsin Department of Natural Resources declared as hazardous substances the thousands of gallons of melted butter that ran offsite and the mountain of damaged and charred meat products spoiling in the hot sun and creating objectionable odors. The Wisconsin DNR stated that these products posed an imminent threat to human health and the environment. 62 FR 54526.

Our revised definition also reflects EORRA requirements for differentiation. EORRA did not expand or contract the universe of substances that are oils, it only required differentiation, when necessary, between the requirements for facilities storing or using different types of oil. Because at the present time EPA has not proposed differentiated SPCC requirements for public notice and comment, the requirements for facilities storing or using all classes of oil will remain the same. However, we have published an advance notice of proposed rulemaking seeking comments on how we might differentiate among the requirements for the facilities storing or using various classes of oil. 64 FR 17227,

April 8, 1999. If after considering these comments, there is adequate justification for differentiation among the requirements for those facilities, we will propose rule changes.

V - 10 *Partially buried tank*

Background: In 1991, we proposed to define a *partially buried tank* to clarify the distinction between such a tank and a UST. We proposed to define a *partially buried tank* as a storage tank that is partially inserted or constructed in the ground, but not fully covered with earth. We have renamed underground tanks in this rule as “completely buried tanks,” i.e., those tanks completely covered with earth. A *partially buried tank* is an aboveground container for purposes of the part 112.

Comments: The definition as proposed is “undecipherable” and should be rewritten. Suggests another definition for clarity. (121) We should adopt the part 280 UST definition for partially buried tank, which includes any tank system such as tank and piping which has a volume of 10 percent or more beneath the surface of the ground. (90, 180) Asks whether *partially buried tanks* will be subject to both parts 112 and 280, and if not, whether part 112 provides adequate regulation of leaks to the ground. (L17)

Response: We agree that the definition could be clearer and have clarified it. We decline to adopt the part 280 UST definition (at 40 CFR 280.12) and to classify partially buried tanks as completely buried tanks, because they are not. The UST definition might also exclude some tanks or containers which would be covered by the SPCC definition. The UST definition includes tanks whose volume (including the volume of underground pipes connected thereto) are 10 percent or more beneath the surface of the ground. The SPCC definition of “partially buried tank” contains no volume percentage and applies to any tank that is partially inserted or constructed in the ground, but not entirely below grade, and not completely covered with earth. Therefore, some partially buried tanks will continue to be subject to both parts 112 and 280.

We clarify that partially buried tanks may be covered not only with earth, but with sand, gravel, asphalt, or other material. The clarification brings the definition into accord with the coverings noted in the definition of “bunkered tank.” We added a sentence to the definition noting that partially buried tanks are considered aboveground storage containers for purposes of this part.

V - 11 *Permanently closed* (See also section IV.C of this document)

Background: In 1991, in §112.2(o), we proposed to define the term *permanently closed* to clarify whether facilities and tanks are excluded from part 112. In §112.2(o)(1), we proposed to define *permanently closed* as a tank and its connecting lines or a facility from which an owner or operator has removed all liquid and sludge, disposing of removed waste products in accordance with all applicable State and Federal requirements. Proposed §112.2(o)(2) would have provided that to call a tank or facility *permanently closed*, an owner or operator must have tested the tank for and rendered the tank free from explosive vapor, using a combustible gas indicator, explosimeter, or

other type of atmospheric monitoring instrument to determine the lower explosive limit (LEL). The proposed definition further would have provided that tank vapors must remain below the LEL, as defined by EPA and the Occupational Safety and Health Administration (OSHA). Proposed §112.2(o)(3) would require blanking off all connecting lines, closing and locking valves, and posting signs warning that the tank is permanently closed and that there are no vapors above the lower explosive limit.

Comments: *Support for definition.* “The inclusion of a definition of a ‘permanently closed tank’ is helpful.” (27).

Opposition to definition. “It is recommended that the concept of ‘permanently closed’ tanks be removed from the SPCC regulations. If a tank is not used for the storage of oil, it is simply not subject to the provisions of the SPCC regulations.” (42, 67, 85, 86, 110, 125, 175) We should include in the term *permanently closed* those tanks without oil and with all connections severed. (101, 125, 165, 170, L2, L15) If our primary goal is to protect navigable waters, our definition of *permanently closed* is too stringent. (75, 86, 125, 155, 167, 170)

Other substances. Our definition should include tanks that have been permanently closed and then loaded with liquid other than oil. (51)

Regulatory criteria. “It is important that the Agency separate permanently closed tanks from regulated tanks and make the criteria easy to observe during SPCC inspections.” (168, 190)

Connecting lines. Support the proposed provision in the *permanently closed* definition to blank off all connecting lines. However, we should require that owners or operators blank off all connecting lines at both ends. (27, L12) We are overreaching our authority by requiring lines to be blanked off. (58) Asks that we clarify the term *connecting lines*. Assumes that we mean the sections of pipe that run between the tank and the nearest block valve. (67, 96, 102)

Cost. It would be expensive to eventually close tanks currently in operation because owners or operators will have to pay for explosivity detection services, determination of LEL, placarding tanks, and waste disposal. (28, 31, 165)

Decommissioned tanks. “The definition should include tanks which have been decommissioned in this manner. ... If the decommissioning procedure follows that prescribed by the procedure in the currently-proposed ‘permanently closed’ definition, a decommissioned tank no longer poses a threat of oil pollution.” (L12)

Explosive vapors. “... (P)rovisions relating to combustible vapors or dust clearly fall outside the scope of the Clean Water Act.” (42, 58, 67, 71, 75, 95, 102, 110, 125, 155, 167, 170, 175, L12) EPA should eliminate the 25% LEL because it is “NOT universally acceptable to OSHA.” (33) Rather than render each tank free of explosive vapor, owners or operators should maintain tanks below the LEL for the tank’s material. (33) Vapor testing for small tanks is excessive and should be necessary only for a tank with a

capacity greater than 42,000 gallons or 1,000 barrels. (113) It would be difficult or impossible to remove all vapors, and we should delete this element from the *permanently closed* definition. (L2) Detection services would be too expensive. (L15)

Signs. The proposed requirement to post a sign on permanently closed tanks is beyond the scope of our CWA authority. (58) “Additionally, the placement of a sign on a tank indicating that it has been gas freed is not a good safety practice. This could lead an inexperienced worker to believe that confined space entry without additional testing of the atmosphere within the tank is acceptable. This could also apply to someone initiating hot work, such as welding or cutting, on the tank. If gases were to build up within the tank after the initial gas freeing procedure for some unexpected reason, a sign, such as that proposed, could have catastrophic results while providing no benefit.” (67, 86, 102, 110, 175, L2)

Retroactive enforcement. “The definition of ‘permanently closed’ should not be applied retroactively to tanks that have been abandoned prior to adoption of this definition.” Such tanks, in most instances, have been abandoned and empty for many years and pose no threat of an oil spill. It would be a severe economic burden to require that operators perform the proposed procedures on such a wide universe of tanks.” The commenters did not provide specific cost estimates. (28, 31, 37, 101, 113, 165, L15)

Scope of rule. The provisions to regulate permanently closed tanks are unclear. Asks whether we proposed to exclude permanently closed tanks from *all* of 40 CFR part 112. (84) Part 112 technical requirements should not apply to permanently closed tanks. (102)

Temporarily closed tanks. Suggests “temporarily closed” definition.” Temporary tanks should be excluded from the definition “provided the operator can show that the tanks have been shut-in and all fluid removed down to the pipeline connection.” (71, L2, L12)

Waste disposal.

Authority. “USEPA does appear to be within its statutory authority to require removal of all liquid and sludge from a permanently closed tank since, conceivably, such liquid or sludge, if released, could cause a discharge of oil in harmful quantities into a navigable water.” (58)

Opposition to proposal.

Other programs. “Waste disposal is covered under other programs and should not be a consideration for spill prevention unless flowable oil is part of the waste.” (28, 31, 42, 101, 110, 165, 167, L15)

Unnecessary. The definition is a “surreptitious means of inserting regulations with the definition section of 40 CFR part 112. ... (D)isposition of tank contents has nothing to do with the definition of a tank.” (110)

Sludge removal. “A small amount of sludge left on the bottom of the tank should not prevent it from being classified as empty.” (75) “‘Permanently closed’ should not require the total removal of sludge unless the sludge is free flowing, provided that the provision for meeting explosive vapors can be met. It has been our experience that it can be very difficult to remove old sludge from #6 fuel oil tanks. It appears that the only way of removing the sludge is to dismantle the tank.” (161)

Response: *Support for proposal.* We appreciate commenter support. A definition is necessary to clarify when a container is permanently closed and no longer used for the storage of oil. Containers that are only closed temporarily may be returned to storage purposes and thus may present a threat of discharge. Therefore, they will continue to be subject to the rule.

Connecting lines. We agree with the commenter’s assumed definition of connecting lines. Connecting lines that have been emptied of oil, and have been disconnected and blanked off, are considered permanently closed.

Cost. We have deleted the proposed requirements to render the container free of explosive vapor by testing to determine the LEL. We have also deleted all references to waste disposal. The sign noting that a container is permanently closed (with date of closure) should be relatively inexpensive.

Decommissioned tanks. If “decommissioning” refers to the criteria for permanent closing of a container, then there is no need to include such terminology in the definition because permanent closure will include such tanks. Otherwise, the containers are not permanently closed and should not be included.

Explosive vapors. We deleted proposed §112.2(o)(2) on the suggestion of commenters that references to explosive vapors are an OSHA matter and inappropriate for EPA rules. We modified proposed §112.2(o)(3) to eliminate the reference to signs warning that “vapors above the LEL are not present,” because the operator cannot guarantee that warning remains correct. To help prevent a buildup of explosive vapors, we have revised the definition to provide that ventilation valves need not be closed. We agree with commenters that a sign might be misleading and dangerous.

Non-oil products. Containers that store products other than oil and never store oil, are not subject to the SPCC rule whether they are “permanently closed” as defined or not. If the containers sometimes store oil and sometimes store non-oil products, they are subject to the rule.

Retroactive enforcement. We believe that containers that have been permanently closed according to the standards prescribed in the rule qualify for the designation of “permanently closed,” whether they have been closed before or after the effective date of the rule. Containers that cannot meet the standards prescribed in the rule will not

qualify as permanently closed. We disagree that the cost of such closure is prohibitive. We have simplified the proposal by deleting the proposed requirement to render the tank free of explosive vapor. Therefore, costs are lower. To clarify when a container has been closed, we have amended the rule to require that the sign noting closure show the date of such closure. The date of such closure must be noted whether it occurred before or after the effective date of this provision. Some States and localities require a permit for tank closure. A document noting a State closure inspection may serve as evidence of container closure if it is dated.

Scope of rule. The exemption for a permanently closed container or facility applies to all of part 112.

Waste disposal. Reference to waste disposal in accordance with Federal and State rules in proposed §112.2(o) was deleted as unnecessary surplus. EPA agrees that other programs adequately handle waste disposal.

V - 12 *Person*

Background: In the 1991 proposal, we proposed to include a definition of *person* that was substantively unchanged from the current rule.

Comments: “EPA should either modify its regulatory definition of person, or make clear that the United States is bound by every provision of these regulations for any failure to comply.” (35)

Response: See the discussion under §112.1(c) for the applicability of the rule to Federal agencies and facilities.

V - 13 *Production facility*

Background: The definition of “production facility” replaces two definitions in the proposed rule, i.e., *Oil drilling, production, or workover facilities (offshore)*, proposed §112.2(j), and *Oil production facilities (onshore)*, proposed §112.2(k). We replaced the two proposed definitions with the revised definition for editorial brevity as the proposed definitions contained many identical elements. This editorial effort effects no substantive changes in the requirements for the particular types of production facilities. Each facility must follow the requirements applicable to that facility, which is generally based on its operations, for example, a workover facility.

Comments: *Editorial change.* “The proposed regulations contain new definitions for oil production facilities (onshore) and oil production facilities (offshore). These definitions should be replaced by a single definition of ‘production facility’ that is identical to that found in 49 CFR §195.2. ... EPA should not develop new definitions for terms already defined in existing regulations that would result in wide spread confusion among the regulated community.” (95, 102) We should include a definition for *onshore drilling and workover facilities*. The proposed definitions of the terms *oil production facility (onshore)*

and *oil production facility (offshore)* are ambiguous, because of inclusion of the phrase, “may include.” (154)

Flowlines, gathering lines, wells and separators. “Oil production facilities should not include wells, flow lines, gathering lines or separators.” (101, 165) “These pipelines (gathering lines) have never been subject to such (SPCC) requirements. They are truly transportation lines subject to Department of Transportation regulations.” (71) “The term should also exclude oil gathering lines since it is virtually impossible to comply with certain provisions of the regulation without excessive and unrealistic expense. How, for example would an operator provide the necessary containment for his gathering lines pursuant to section 112.7(c)?” (113)

Natural gas processing operations.

Applicability of rules. “IPAA recommends clarification of the definition of ‘oil production facilities’ at 40 C.F.R. §112.2 to ensure that natural gas processing operations are treated as oil production facilities under the rules. That clarification should ensure the appropriate level of regulation for those related facilities and avoid inadvertent application of requirements designed for larger refining and marketing facilities to natural gas processing.” (31, 86, L12)

Risk. “After 20 years of SPCC regulation of E&P operated natural gas processing facilities, there is no evidence that demonstrates that these facilities have a different or higher risk of causing oil spill pollution of navigable waters. Therefore, the oil pollution requirements should not be different than those for other E&P facilities.” (L12)

Single geographical oil or gas field, single operator. “The inclusion of the phrases ‘in a single geographical oil or gas field’ and ‘operated by a single operator’ in this definition is confounding. The producing segment of the industry in some cases needs to be able to combine facilities into one SPCC plan with an identification of the wells to which that plan applies. We question whether the inclusion of the word ‘single’ would preclude an operator’s ability to do so.” (167)

Response: *Editorial change. DOT definition.* We changed the proposed definition to be more consistent with the DOT definition, found at 49 CFR 195.2, in response to a commenter who urged consistency in EPA and DOT definitions. We added the uses of the piping and equipment detailed in the DOT rule to our proposal, for example, “production, extraction, recovery, lifting, stabilization, separation, or treating” of oil. The terms “separation equipment,” used in the proposed definition of “oil production facilities (onshore),” and “workover equipment,” used in the proposed definition of “oil drilling, production, or workover facilities (offshore),” were combined into a generic “equipment.” However, we also modified the proposed definition to reflect EPA jurisdiction. We added the word “structure,” which was not in the DOT definition, to cover necessary parts of a production facility. We also added examples of types of piping, structures, and equipment. These examples are not an exclusive list of the possible piping, structures,

or equipment covered under the definition. The new definition encompasses all those facilities that would have been covered under both former proposed definitions. As we proposed in 1991, and as in the current rule, we have retained geographic and ownership limitations.

Editorial change. We have eliminated the potential ambiguity caused by the words *may include* by substituting the word *means*.

Flowlines, gathering lines, wells and separators. EPA disagrees that flowlines and gathering lines, as well as wells and separators, should be excluded from the definition. These structures or equipment are integral parts of production facilities and should therefore be included in the definition. We also disagree with the argument that because the installation of structures and equipment to prevent discharges around gathering lines and flowlines may not be practicable, EPA will be flooded with contingency plans. First of all, secondary containment may be practicable. In §112.7(c), we list sorbent materials, drainage systems, and other equipment as possible forms of secondary containment systems. We realize that in many cases, secondary containment may not be practicable. If secondary containment is not practicable, you must provide a contingency plan in your SPCC Plan following the provisions of part 109, and otherwise comply with §112.7(d). We have deleted the proposed 1993 provision that would have required you to provide contingency plans as a matter of course to the Regional Administrator. Therefore, you will rarely have to submit a contingency plan to EPA. The contingency plan you do provide in your SPCC Plan when secondary containment is not practicable for flowlines and gathering lines should rely on strong maintenance, corrosion protection, testing, recordkeeping and inspection procedures to prevent and quickly detect discharges from such lines. It should also provide for the quick availability of response equipment.

Natural gas processing operations. Because natural gas is not oil, natural gas facilities that do not store or use oil are not covered by this rule. However, you should note, that drip or condensate from natural gas production is an oil. The storage of such drip or condensate must be included in the calculation of oil stored or used at the facility.

Single geographical oil or gas field, single operator.

Single geographical oil or gas field. The phrase “a single geographical oil or gas field,” may consist of one or more natural formations containing oil. The determination of its boundaries is area-specific. Such formation may underlie one or many facilities, regardless of whether any natural or man-made physical geographical barriers on the surface intervene such as a mountain range, river, or a road.

Single operator. We disagree that the term “a single operator” is confusing. An “owner” or “operator” is defined in §112.2 as any “person owning or operating an onshore facility or an offshore facility, and in the case of any abandoned offshore facility, the person who owned or operated or maintained such facility

immediately prior to abandonment.” A “person” is not restricted to a single natural person. “Person” is a defined term in the rule (at §112.2) which includes an individual, firm, corporation, association, or partnership.

V - 14 SPCC Plan or Plan (see also section X.A)

Background: In 1991, we proposed to define an *SPCC Plan* or *Plan* to further explain its purpose and scope.

Comments: *Compliance.* “An SPCC plan should not be a chronicle of actions taken to comply with the regulations. Rather, an SPCC plan should contain information which is necessary to prevent, control, or take countermeasures in response to a discharge of oil. Maintenance of records to demonstrate compliance is addressed in other sections.” (42)

Prevention v. Response. “Change the definition of ‘SPCC Plan’ to ‘Spill Prevention and Response Plan’ means a plan consisting of two separate entities: a Spill Prevention Plan (SPP or ‘plan’), described in sections 112.3 through 112.11 of this part, and a Spill Response Plan described in sections to be added.” (121)

Response: *Compliance.* We agree that the Plan does not document compliance, but merely spill prevention measures, and have deleted the sentence noting that the Plan documents compliance with the rule. Compliance is determined by comparing the contents of the Plan with the regulations.

Prevention v. Response. In 1997, we proposed a new definition of an *Spill Prevention, Control, and Countermeasure Plan, SPCC Plan, or Plan*; and withdrew the 1991 proposed definition. See the preamble to today’s final rule and the Response to Comments Document for the 1997 proposal for a discussion of the revised proposal. The 1997 proposal broadened the acceptable formats of SPCC Plans. In 1994, we finalized response plan requirements.

V - 15 Spill event

Background: In 1991, we proposed to revise the definition of a *spill event* to make it consistent with the proposed changes in §112.1, reflecting the expanded scope of CWA jurisdiction. We proposed to define a *spill event* as a discharge of oil as described in §112.1(b)(1).

Comments: “‘Spill event’ should refer only to discharges to navigable waters.” (28, 31, 101, 165, L15) “There is a great deal of confusion over the words: ‘spill,’ ‘spill events,’ and ‘discharges,’ ‘leak,’ etc. EPA should use this opportunity to define the term ‘discharge’ as a reportable event under 40 CFR 110 and remove the term ‘spill event’ from the regulations. The reason for this is that ‘discharge’ is the word used in 40 CFR 110, and EPA should be consistent in the use of this important word. Then ‘spills,’ ‘leaks,’ ‘release,’ ‘drips,’ etc. can be reserved for those events where oil escapes from some containment system, but does not get to water. This would be a great improvement over current terminology.” (121)

Response: We have withdrawn the proposed definition of “spill event,” and have also deleted the term from the rule. We take this action because the term is not mentioned in the CWA and is unnecessary. The term is unnecessary because the word “discharge” is adequate. “Discharge” is the term used in the CWA. A discharge as described in §112.1(b) is the same as a spill event.

V - 16 *Storage capacity*

Background: In 1991, we proposed to define *storage capacity* to clarify the necessity of counting container *capacity* -- not the actual content -- in calculating the regulatory threshold. We stated that for determining the applicability of part 112, the *storage capacity* of a container means the total capacity of the container, whether the container is filled with oil or a mixture of oil and other substances.

Comments: *Opposition to proposal.* “As proposed, if a vessel contains only trace amounts of oil, its entire volume must be included.” (28, 31, 58, 67, 85, 86, 95, 101, 102, 103, 106, 113, 165, 167)

Secondary containment containers. “The extremely broad definition proposed for ‘storage capacity’ also could require that a tank or container that is used to provide secondary containment be considered when determining the storage capacity of a facility. This could discourage the installation of containers for use as secondary containment at small facilities that would otherwise be exempt from these regulations.” (67, 85, 95)

Waste treatment facilities. “Based on the proposed definition, the entire volume of any container including the non-usable space at the top of the tank, containing trace amounts of oil must be used to determine applicability of these regulations. As a result, storage tanks used to store or treat wastewaters are likely to have to be considered when determining oil storage capacity since many wastewaters have incidental oil content prior to treatment. It is important to note that the issue of tanks containing trace amounts of oil does not apply only to the petroleum industry. It is not uncommon for municipal stormwater runoff to contain trace amounts of oil due to runoff from parking lots and city streets. The proposed definition ... could result in these regulations being applicable to stormwater surge tanks used by POTWs due to the incidental oil content of stormwater runoff.” (67, 72, 95)

Standard of measurement.

Bulk storage tanks only. “The proposed definition ... needs to be amended so that it is clear that only tanks or containers meeting the definition of a bulk storage tank, and only the oil storage capacity of that tank, need be considered.” (67, 175)

Design capacity. “Some electrical equipment which may fall under these regulations contain interior components which reduce the volume of oil contained. The design, not total capacity as might be measured by the dimensions unadjusted for these components, is more appropriately used in this situation.” (183)

Mixtures. “The proposed definition of ‘storage capacity’ specifies that the total capacity of a tank is to be considered for the purpose of this regulation, regardless of whether the tank stores oil or an oil mixture. We strongly believe this clarification should become part of the final rule.” (27)

Oil-water separators. Storage capacity should not include the capacity of flow-through separators. (31, 165, L15)

Volume. Volume is the proper measure of storage capacity, not total capacity. (160)

Working capacity. Working capacity, “that is, the volume of the tank used for storage,” should be the standard, rather than shell capacity. (86)

Response: *Support for proposal.* We appreciate commenter support.

Editorial changes and clarifications. We use the word “container” instead of “tank or container,” because a tank is a type of container. We have clarified the definition to provide that the storage capacity of a container is the volume of oil that the container *could* hold, and have therefore substituted the words “shell capacity” of the container for “total capacity.” This is merely a clarification, and not a substantive change. We also deleted the words “for purposes of determining applicability of this part,” because the words were unnecessary. We also deleted the last phrase of the proposed definition, “whether the tank or container is filled with oil or a mixture of oil and other substances,” because the contents of the container do not affect the definition of its shell capacity.

Exclusions - small containers; waste treatment facilities. Small containers. This definition is applicable to both large and small storage and use capacity. Owners or operators of small facilities above the regulatory threshold are subject to the rule, and need to know how to calculate their storage or use capacity.

However, in the applicability section of the rule, we have excluded aboveground or completely buried containers of less than 55 gallons from the scope of the SPCC rule, addressing the comments of those commenters who argued for a minimum container size. See §112.1(d)(5). A container above that size that is available for use or storage containing even small volumes of oil must be counted in storage capacity.

Secondary containment containers. Containers which are used for secondary containment and not storage or use, are not counted as storage capacity.

Standard of measurement. In most instances the shell capacity of a container will define its storage capacity. The shell capacity (or nominal or gross capacity) is the amount of oil that a container is designed to hold. If a certain portion of a container is incapable of storing oil because of its integral design, for example electrical equipment or other interior component might take up space, then the shell capacity of the container is reduced to the volume the container might hold. When the integral design of a container has been altered by actions such as drilling a hole in the side of the container so that it cannot hold oil above that point, shell capacity remains the measure of storage capacity because such alteration can be altered again at will to restore the former storage capacity. When the alteration is an action such as the installation of a double bottom or new floor to the container, the integral design of the container has changed, and may result in a reduction in shell capacity. We disagree that operating volume should be the measurement, because the operating volume of a tank can be changed at will to below its shell capacity.

The keys to the definition are the availability of the container for drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil, and whether it is available for one of those uses or whether it is permanently closed. Containers available for one of the above described uses count towards storage capacity, those not used for these activities do not. Types of containers counted as storage capacity would include flow-through separators, tanks used for “emergency” storage, transformers, and other oil-filled equipment.

Waste treatment facilities. We agree with the commenter that a facility or part thereof (except at an oil production, oil recovery, or oil recycling facility) used exclusively for wastewater treatment and not to meet any part 112 requirement should not be considered storage capacity because wastewater treatment is neither storage nor use of oil. Therefore, we have exempted such facilities or parts thereof from the rule. However, note that certain parts of such facilities may continue to be subject to the rule. See the discussion under §112.1(d)(6).

V - 17 Wetlands (see also “navigable waters.”)

Background: In 1991, we proposed to define *wetlands*, a term used in the definition of *navigable waters*. We noted that the proposed definition conformed with the part 110 definition.

Comments: *1987 Wetlands Manual.* “The definition of wetlands should conform to the definition in the ‘Federal Manual for Identifying and Delineating Jurisdictional Wetlands’.” “We strongly urge that the definition of ‘wetlands’ proposed in this rulemaking be either deleted or scaled back to the present definition set forth in 40 CFR 230.3. We suggest that deferral is required because the effort of the four agencies has received much more public scrutiny than this proposed rule, and EPA will have a better record upon which to base a definition that covers the entire range of programs, rather than one specific program as here.” (64, 73, 78, 106, 145, 167, 175)

Examples of wetlands. “The ‘Wetlands’ definition includes a series of examples which may not be appropriate or correct and should be deleted.” (64)

Phreatophytes. “Phreatophytes, hydric soils, and saturation should be a part of the definition.” (167)

Expansion of definition. The proposed definition would significantly expand *wetlands* beyond what was in the delineation manual. (73, 106) “...(W)e deserve to know exactly what the rules hold in store for us. The jurisdiction of this regulation must be well-defined; incorporating vague references to ‘wetlands’ and ‘sensitive ecological area’ is not acceptable to the agriculture industry and will no doubt pose serious enforcement problems to the Agency.” (139)

NPDES program. “Again, the protections provided by a regulatory permit program, as in the wetland regulations, are not necessary under the OPA, which seeks to identify and preclude the discharge of oil to ‘waters’ from high risk bulk oil storage. Wetlands and other aquatic sites are adequately protected under the Clean Water Act. ... (N)avigable waters alone should serve as the jurisdictional trigger under the OPA.” (35)

Response: *Examples of wetlands.* The examples listed in the definition are intended to help the reader with guidelines to identify wetlands. While the examples generally represent types of wetlands, they are not intended to be a categorical listing of such wetlands. There may be examples listed that under some circumstances do not constitute wetlands. We believe that the 1987 Wetlands Manual is a useful source material for wetlands guidance. It would be impossible to specify in a rule every type of situation where wetlands occur. The examples listed in the definition are not exclusive, but provide help in clarifying what may be a wetland.

Expansion of definition. We disagree that the definition expands the term “wetlands” beyond what is in the 1987 Wetlands Manual. It does nothing to substantively expand our jurisdiction over wetlands.

Rulemaking process. We disagree that we should not define “wetlands.” While the NPDES program may define *wetlands*, the NPDES program and the SPCC program have different purposes, and a definition is needed for part 112. The definition is necessary to supply guidance to the regulated public. The definition of “navigable waters” includes wetlands, as defined in §112.2, because wetlands are waters of the United States. We note that 40 CFR 230.3 and the delineation manual serve different purposes than part 112. We believe that it is important to base the definition on the part 110 definition, because of the integral connection between parts 110 and 112.

V - 18 Other definitions

Background: Several commenters suggested definitions which we did not propose.

Comments: *Consistency in definitions.* In general, we should make the definitions in part 112 consistent with corresponding definitions provided in other regulations. There is no justification for redefining terms specific to the SPCC regulation and to do so would cause “significant confusion.” (167)

Specific definitions requested.

Connecting line. (113)

Contingency plan. (82)

Flow-through process tank. We should define *flow-through process tank* in §112.2. (28, 31, 113, 165, L15)

Good engineering practice. (33)

Impervious. (27, L12)

Oil production facility transfer operation. We should include a definition of *oil production facility transfer operation* in §112.2. (L12)

Prevention, response, mitigation. We should define the terms *prevention*, *response*, and *mitigation*: provides suggested text. (121)

Professional Engineer. (43)

Response: *Consistency in definitions.* We agree that definitions in part 112 should be consistent with corresponding definitions in other regulations when it is appropriate. However, sometimes differing definitions are necessary to serve differing program goals.

Specific definitions requested. For the suggested definitions not proposed, a dictionary or industry definition is sufficient.

Transfer operation. A transfer operation is one in which oil is moved from or into some form of transportation, storage, equipment, or other device, into or from some other or similar form of transportation, such as a pipeline, truck, tank car, or other storage, equipment, or device.

Category VI - Preparing and implementing Plans.

VI - A: Time frames for preparing and implementing Plans - §112.3(a), (b), (c)

Background: Section 112.3(a) of the current rule requires the owner or operator of a facility existing on or before the effective date of the rule that is subject to the rule to prepare and implement a Plan within one year after the effective date of the rule. In 1991, we proposed in §112.3(a) to require an owner or operator of a facility in operation on or before the effective date of the rule to prepare and implement a Plan within 60 days following that date.

Section 112.3(b) of the current rule requires the owner or operator of a facility becoming operational after the effective date of the rule to prepare a Plan within six months after the facility begins operations and implement it within one year. In 1991, we proposed to require the owner or operator of a facility beginning operations more than 60 days after publication of the rule to prepare and fully implement an SPCC Plan before beginning operations.

Section 112.3(c) of the current rule requires an owner or operator of a mobile or portable facility to prepare and implement a Plan as required under §112.3(a), (b), and (d). In 1991, we proposed to require an owner or operator of a mobile or portable facility to prepare, implement, and maintain an SPCC Plan as required under proposed §112.3(a), (b), and (d), noting that these owners or operators would not need to prepare a new Plan each time the facility is moved to a new location.

Comments: *Time period to prepare and implement a Plan.*

Support for proposal. “The proposed provision ... requiring that ‘a facility SPCC Plan be prepared and fully implemented before a facility begins operations...’ is commendable.” “This is protective of the environment and consistent with many other environmental requirements.” (43, 62, 80, 90, 121, 181, 185, and L11)

Opposition to proposal. Re proposed §112.3(a): “Sixty days is not a practical time for compliance for Appalachian producers, who literally have thousands of sites throughout the seven Appalachian states.” Re proposed §112.3(b): “It is recommended that the language of current §112.3(b), which allows six months for the preparation of the plan, be retained.” (3, 23, 27, 34, 36, 42, 58, 66, 68, 71, 101, 107, 111, 113, 116, 134, 189)

Implementation and training. Our proposal is impracticable because it does not allow new facility owners or operators enough time to implement the Plan and train the appropriate personnel. (66)

Acquired facilities. “BFI would also ask the EPA to clarify how it would interpret this provision where an acquisition is being made. These acquired facilities under prior ownership may not have been aware of the SPCC rule and its provisions and hence may

not have put a plan into place. BFI would propose to the EPA that this does not constitute a 'new facility' but an existing facility and that operations need not cease, while notification to EPA is being made and an SPCC Plan is developed and implemented." (23)

Alternate time frames suggested

Existing Plans.

180 days. (28, 36, 67, 68, 79, 85, 90, 91, 102, 107, 111, 116, 128, 134, 141)

Next triennial review. "If EPA insists on making these small facilities comply with the proposed changes, then they should only be required to comply at the time of routine plan recertification, not before." (29, 58, 62, 78, 83, 101, 113, 116, 141, 145, 1164, 185, 189, L2, L14)

Three years plus seven years. "A more realistic compliance period would be a minimum of three years for the preparation of plans with an additional seven years for the completion of necessary construction, if any." (98)

180 days or after updates. "We suggest that plans be allowed to be updated whenever a change occurs or when the next triennial review would occur, whichever is sooner." (71)

5-7 years. "A five to seven year phase-in compliance schedule similar to the approach taken with EPA's underground storage tank program would be a more reasonable and achievable approach." (92)

New Plans.

180 days. "It is recommended that the language of current §112.3(b), which allows six months for the preparation of the plan, be retained." (101)

Cost. The costs associated with the proposal "cannot be justified in terms of the CWA or in anticipated benefits to the public. First, the start up volume associated with beginning operations at an onshore oil production facility is small. Thus, any discharge associated with commencement of operation would also be small. Second, the history of performance in the start up of a well is very good, both in terms of industry's standards and in terms of supervision by State regulatory authorities. Thus, even the small discharge which might occur is unlikely. Third, the cost associated with the engineer is disproportionately high when his services at a small operation (with low risk) are compared to similar costs at a large facility (where the risk is much higher)." (42)

Extensions. We should grant an automatic extension of six months, at a minimum, if the RA does not decide within 30 days of receiving the extension request. If an RA grants or denies an extension, we should require a Professional Engineer (PE) to certify that the RA's decision was made in accordance with "good engineering practice." (33, 42, 66,110, 133, 167, L12)

Small facilities. Criticizing proposed requirement to have Plan developed and implemented before beginning operations, "...BFI urges that small facilities (e.g., those with 10,000 gallons or less of above ground oil storage) should be eligible for a reasonable time period to develop and implement this plan while operations occur. Although the EPA provided the potential for extensions from the Regional Administrator, these extensions are not automatic and the sheer burden to the Regional Administrator from numerous small facility requests would be unmanageable." (23)

Mobile facilities.

General Plans. We should allow a "strong generic spill contingency plan" for a mobile oil and gas production facility until the owner or operator can prepare and implement the SPCC Plan. Seeking an extension from the Regional Administrator (RA) could delay start-up, and we should require the owner or operator of a mobile facility to prepare an SPCC Plan within 60 days after the facility begins operations. (68) Commends EPA for: "Retaining provisions in Section 112.3(c) that allow owners/operators of onshore and offshore mobile or portable facilities to prepare a general plan for such a facility so that a new plan need not be prepared each time a facility is moved to a new site." (97)

Multi-well drilling program. "We question whether plan updates will be required in a field where a multi-well drilling program is underway. Updates of the plan should be required only after the drilling program is complete." (167)

No Plans. The definition of facility "contemplates a fixed structure, or unit, which serves a purpose at the place where it is fixed. Where equipment is mobile, its physical surroundings are subject to change. Conceivably, a SPCC Plan for a mobile 'facility' would have to be amended each time the mobile equipment is moved. This is likely to be an unworkable requirement. For these reasons, mobile equipment should not be considered a facility for purposes of SPCC regulations." (188)

NPDES coordination. We should coordinate SPCC regulation with the National Pollutant Discharge Elimination System (NPDES) storm water discharge permit system. (76)

Start of operations. "Since many facilities initially become partially operational, defining the start of operations is not always clear. A better approach would be to require that a response team be in place and the notification portion of the plan be completed prior to

beginning operations and the entire plan to be completed within six (6) months of startup.” (36)

“*Submittal.*” We should clarify the term *submittal* in the Preamble, because we do not require facility owners or operators to submit SPCC Plans to us under the regulation. (95, 101)

Response: *Time period to prepare and implement a Plan.*

Support for proposal. We appreciate the expressions of support for our proposal. We have been persuaded by commenters that a longer phase-in period than 60 days is required for facilities currently in operation or about to become operational within one year after the effective date of this rule.

Facilities currently in operation. For a facility in operation on the effective date of this rule, we changed the dates in the proposed rule for preparation and implementation of plans from 60 days to a maximum of one year to accord with the time frames in the current rule. The owner or operator of a facility in operation on the effective date of this rule will have 6 months to amend his Plan and must fully implement any amendment as soon as possible, but within one year of the effective date of the rule at the latest. The owner or operator of a facility which has had a discharge as described in §112.1(b), or reasonably could be expected to have one, already has an obligation to prepare and implement a Plan.

Facilities becoming operational within one year after the effective date of the rule (13 months following publication in the Federal Register). If you begin operations on or after the effective date of the rule through one year after the effective date of this rule (the effective date of the rule is 30 days after the Federal Register publication date), you will have until one year from the effective date of this rule to prepare and implement your Plan. In other words, if the rule becomes effective on January 1, and you begin operations on January 2, you must prepare and implement your Plan by January 1 of the following year. If you begin operations on June 30, you still have until January 1 of the following year to prepare and implement your plan. If you begin operations on December 31, you still have until January 1 (the next day) of the following year to prepare and implement your Plan. The rationale for the time frame in the rule is that you will have had notice of the Plan preparation and implementation requirements from the publication date of the rule, a period of 30 days plus one year. In addition, you would already have had notice of the general requirement for preparation of an SPCC Plan from the current part 112 regulations. Therefore, the owner or operator of a facility planning to become operational within one year after the effective date of this rule should start working on his Plan in time to have it fully implemented within the year.

New facilities. The owner or operator of a facility that becomes operational more than one year after the effective date of this rule must prepare and implement a Plan before beginning operations. Experience with the implementation of this regulation shows that many types of failures occur during or shortly following startup and that virtually all prevention, containment, and countermeasure practices are part of the facility design or construction.

A year phase-in period is in line with legitimate business and investment expectations. It allows a reasonable period of time for facilities to undertake necessary constructions, purchases of equipment, or to effect changes of procedures. And again, the general requirement for preparation of a Plan already exists in part 112, so new facilities should already have been aware of the need for a Plan.

Acquired facilities. For SPCC purposes, we consider acquired facilities as facilities that are already operating rather than new facilities because these facilities must already have SPCC Plans if they exceed applicable thresholds.

Cost. We disagree that the rule places a disproportionate impact on the regulated facilities, whether large or small. Most of the requirements of the rule are practices that many facilities would follow whether the rule required them or not. Not only have we fully assessed the costs for small entities, but the applicability criteria for part 112 also eliminate a number of small businesses from SPCC coverage. While amounts of oil stored may be small at some facilities, even a small discharge may be disastrous to the environment. We also disagree that small facility start-ups cause fewer discharges than start-ups at large facilities. Our experience shows the contrary; and the commenter presents no evidence for his assertion.

We also disagree that the cost of PE certification at a small facility is disproportionate to that of certification at a large facility. A small facility is more likely to require a simpler, less expensive Plan that costs less to prepare and implement than a Plan at a large facility.

Finally, we disagree that we should treat large and small facilities differently under §112.3(b). Either type of facility may be the source of a discharge as described in §112.1(b).

Extensions. While we have extended the time period for compliance, we understand that some facilities may still need extensions of time to comply. Extensions may be necessary to secure necessary manpower or equipment, or to construct necessary structures. If you are an owner or operator and an extension is necessary, you may seek one under §112.3(f). If no Plan amendments are necessary after you review today's rule, you must maintain your current Plan and cross-reference its elements to the redesignated requirements. We disagree that we should grant an automatic extension of six months, at a minimum, if the RA does not decide within 30 days of receiving the extension request because compliance with the rest of the Plan that is not affected by

the extension request remains in effect. We also disagree that we should require a Professional Engineer (PE) to certify that the RA's decision was made in accordance with "good engineering practice." The RA has the assistance of PEs when necessary.

Mobile facilities. We agree that the physical surroundings of mobile facilities are subject to change. However, we disagree that changing physical surroundings should exempt mobile facilities from the rule. Mobile facilities may have "general" Plans and need not prepare a new Plan each time the facility is moved to a new site. When a mobile facility is moved, it must be located and installed using the spill prevention practices outlined in the Plan for the facility.

Mobile facilities currently in operation are assumed to have implemented Plans already, because they are currently legally required to do so. Both new and existing mobile facilities must have Plans prepared and fully implemented before operations may begin.

If after your review of today's rule, you decide that no amendment to your Plan is necessary, except for cross-referencing, you may continue to operate under your existing Plan, but you must promptly cross-reference the provisions in the Plan to the new format. Extension requests under §112.3(f) are also available for mobile facilities under the proper conditions.

Multi-well drilling programs. It is not necessary to amend the Plan every time you drill a well in a field containing multiple wells. A general Plan will suffice.

NPDES coordination. We allow use of a Best Management Practice Plan (BMP) prepared under an NPDES permit to serve as an SPCC Plan if the BMP meets all of part 112 requirements. When it does not, it may be supplemented. Therefore, we end duplicate paperwork requirements. Furthermore, under §§112.8(c)(3) and 112.9(b)(1), an owner or operator may, at his option, use records required under NPDES permit regulations to record stormwater bypass events for SPCC recordkeeping purposes.

Small facilities. With the extended time line we have provided, all facilities, large or small, have adequate notice and time in which to prepare and implement a Plan.

Start of operations. Start of operations is when you begin to store or use oil at a facility. Often this may be a testing or calibration period prior to start up of normal operations. With the extended time line we have provided, no response team is required, but such a team may be a good engineering practice. At a minimum, you must prepare and implement a Plan as required by this rule.

"Submittal." The word *submittal* was incorrectly referred to in the rule. See 56 FR 54618. The commenters are correct that as a general rule, we do not require any owner or operator to submit a Plan. An owner or operator may be required to submit a Plan in certain circumstances, such as when a facility discharges oil over the threshold amount specified in §112.4(a), or after on-site inspection of the facility.

Training and implementation. We disagree that it is impracticable to train the appropriate personnel before start-up. We note, however, that we have extended the time frame for Plan preparation and implementation beyond what we proposed. Thus, many facilities will have more time for training and implementation, and all facilities will be on notice of the new time frames, thereby allowing time to plan training and implementation before starting operations.

VI - B: Good engineering practice - §§112.3(d)

Background: In 1991, we noted that good engineering practice is the applicable standard for all SPCC Plans. See §§112.3(d) and 112.7. We noted further that this principle requires an owner or operator to incorporate appropriate provisions of applicable regulations, standards, and codes into the Plan.

Comments: *Support for application of good engineering practice.* “Chevron supports the flexibility of the current SPCC Program, which has allowed petroleum industry operations to adapt SPCC provisions at a particular site in accordance with ‘good engineering practice’.” (96, 97)

Deviations. “...(W)e recommend that EPA include in the applicability provision of the proposal, proposed §112.1, a statement that the purpose of the rule is to protect navigable waters from the risk of oil contamination and that implementation of the rule is based on good engineering practice. Specifically, we urge that this section provide that failure to conform to the specific requirements of the rule shall not be a violation where the owner or operator can demonstrate, in the exercise of good engineering practice, either that the alternative practices provide adequate protection against a reasonable risk of discharge to navigable waters or that compliance with the requirements would not contribute to protecting navigable water from a reasonable risk of discharge.” (125, 170)

Industry standards. “...(I)t is not always feasible or consistent with good engineering practice to mandate the same requirements for every facility.” We should rely upon the discretion of local fire regulatory authorities, as we already recognize the model codes of such authorities as consistent with good engineering practice. We should recognize the spill and leak prevention methods of approved nationally recognized regulatory organizations as protection equivalent to our underground storage tank (UST) standards. Recommending such industry standards to owners or operators as guidance provides neither end users nor “entities charged with enforcing EPA standards” with enough specific guidance. We should recognize that the NFPA, BOCA, and UFC historically have regulated aboveground storage tanks (ASTs) of less than 6,000 gallons per tank and 18,000 gallons per site. Industry standards resulting from these regulations provide protection that is equivalent to our standards. (65) “If EPA wants the use of codes and standards to become part of part 112, then it must say so in the regulation (not the preamble). It must also say which codes will be required and under what circumstances they will be required. You cannot be vague about this.” (121)

PE rule certification. “At a minimum, such rules [SPCC] must contain a certification by a Professional Engineer that the rule and preamble have been reviewed by the certifying P.E. and represents Good Engineering Practice.” (110) We should clarify our aim of grounding the rule on good engineering practice. (125)

Response: *Support for application of good engineering practice.* We appreciate commenter support. We have maintained good engineering practice as the standard by which to judge the propriety of various operating procedures, equipment, systems, and

installations at SPCC facilities. Good engineering practice may include use of industry standards.

Deviations. The purpose of the rule is “to prevent the discharge of oil from non-transportation-related onshore and offshore facilities into or upon the navigable waters of the States or adjoining, shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act.).” 40 CFR 112.1(a)(1).

In §112.7(a)(2) of the final rule, we permit deviations from most of the substantive requirements of the rule when the facility owner or operator can explain his reasons for nonconformance, and can provide equivalent environmental protection by other means. Deviations from secondary containment requirements must be based on impracticability. 40 CFR 112.7(d).

Good engineering practice. As we noted in the 1991 preamble (at 56 FR 54617-18), good engineering practice “will require that appropriate provisions of applicable codes, standards, and regulations be incorporated into the SPCC Plan for a particular facility.” We agree with the commenter that the rule needs more specificity in this regard. Therefore, we have amended §112.3(d)(1)(iii) to specifically include consideration of applicable industry standards as an element of the PE’s attestation that the Plan has been prepared in accordance with good engineering practice. We reiterate today, as we did in 1991, that consideration of applicable industry standards is an essential element of good engineering practice. Industry standards include industry regulations, standards, codes, specifications, recommendations, recommended practices, publications, bulletins, and other materials. (See §112.7(a)(1) and (j).) The owner or operator must specifically document any industry standard used in a Plan to comply with this section. The documentation should include the name of the industry standard, and the year or edition of that standard. However, as discussed above, we have chosen not to incorporate specific industry standards into the rule.

Industry standards. We agree that “it is not always feasible or consistent with good engineering practice to mandate the same requirements for every facility.” Therefore, we provide the owner or operator with authority to deviate from most of the rule’s substantive requirements. See §112.7(a)(2) and (d). We also encourage the use of industry standards when appropriate, instead of prescribed frequencies for inspections and tests.

PE rule certification. We disagree that a PE should certify our rulemakings because such certification would not improve the rulemaking process. However, we do have the advice of PEs to help us with the process of rulemaking.

VI-B-1 Industry standards

Comments: *Specific standards.* If we want to incorporate industry codes and standards into part 112, then we should specify which codes and circumstances. (121)

Industry standards inappropriate. “Further, EPA ... recommends Good Engineering Practice including ‘appropriate provisions of applicable codes, standards, and regulation be incorporated into the SPCC Plans for a particular facility.’ Typically these provisions require electricity. However, many existing tanks do not have and never will have electricity. Also, many new E&P facilities will not have electricity available because of the remoteness of the facilities. Further, I am concerned about who will make the decision as to which are ‘appropriate provisions’. ... (A)n industry P.E., after due consideration and visit to a facility, may be overruled by a non-engineer as to what constitutes Good Engineering Practice. This is an abuse of bureaucratic discretion and makes a mockery of State licensing procedures.” (110)

Response: *Specific standards.* While we encourage the use of industry standards where applicable, we are not requiring an owner or operator to comply with specific industry standards or codes. Complying with industry standards or codes may be inappropriate under facility-specific circumstances. Also, were we to incorporate standards and codes into part 112, these documents may become outdated before we could revise the rule. Further, if we incorporate a specific edition of a standard or code into part 112, we may prevent the application of advanced discharge prevention practices and technologies.

Industry standards inappropriate. We do recommend that an owner or operator consider *applicable* standards and codes at existing and new facilities. This approach allows an owner or operator the flexibility to select a system or procedure that reflects good engineering practice. We have relegated all recommendations for the preamble and other guidance documents. In the final rule, we have amended §112.3(d) to specifically include consideration of applicable industry standards as an element of the PE’s attestation that the Plan has been prepared in accordance with good engineering practice.

VI - C PE certification requirement - §112.3(d)

Background: In §112.3(d) of the current rule requires that a PE review and certify an SPCC Plan. Section 112.3(d) provides that in certifying the Plan, the PE (having examined the facility and being familiar with part 112 provisions) attests that “the SPCC Plan has been prepared in accordance with good engineering practices.” In 1991, we proposed to add specificity in the rule to the elements to which the PE attests in certifying an SPCC Plan. These elements were that: the PE was familiar with part 112 requirements; he had visited and examined the facility for which he certified the Plan; the Plan was prepared in accordance with good engineering practice and part 112; required testing was complete; and the Plan was adequate for the facility.

Comments: *Support for certification requirement.* PE Plan review and certification ensures that the facility follows good engineering practice and has an adequate Plan. We should retain the current §112.3(d) text. (54, 67, 86, 97, 102, 105, 118, 155, 164, 182)

Competence. We should require that the PE be qualified by education, training, or experience, since “most States prohibit licensees from engaging in work the engineer is not competent or qualified to perform.” (L25)

Opposition to certification requirement.

Cost. “There are elements of the plan that a PE is typically not qualified to do, for example vulnerability analyses, and yet all plans are to be certified by someone with PE registration. This over-emphasis on engineering qualifications is misplaced and will not guarantee one measure of extra protection for the environment. Such requirements add significantly to the cost of preparing SPCC plans without offsetting benefits.” (109, 162, L2)

Design v. Plan preparation. “EPA must not confuse facility design with SPCC plan preparation. While an engineer may need to design the facility (e.g., tanks, piping, etc.) A scientist is equally capable of describing the facility and developing appropriate emergency response procedures.” (107, 176)

Lack of expertise. A PE may not be “trained in the SPCC regulations” and may lack the ability to apply part 112 requirements in the field. (70) We should require certification by persons possessing “the necessary technical knowledge and skills to develop an effective Plan. ...(M)any PEs lack sufficient multi-disciplinary knowledge and field skills to develop a site-specific Plan adequate to address “all conceivable contingencies.” (186)

Other environmental professionals.

PE can review work of others. We should modify the regulation to allow a site visit by a person under the direct supervision or authority of the PE who certifies the Plan. (67, 74, L4) A PE should not have to visit every facility. A PE who could not evaluate whether to visit a site should take a special test on part 112 before the PE can certify a Plan. Alternatively, if the PE does not conduct a site visit, he should state who provided the data and how. (76) Facility environmental professionals should continue to offer advice “without being encumbered with excessive, questionably beneficial educational and certification requirements.” A Registered, independent, PE should certify the integrity of tanks, piping, containment structures, and other ancillary process equipment. (162) The rule “implies that a Plan or revisions to a Plan can be prepared by non-registered individuals not associated with the PE and that the PE must only review the Plan before certification.” (L25)

Other certifiers. “Many non-engineers have been and are employed by government agencies to review the SPCC plans which they cannot legally certify. This inconsistency is inappropriate and should be eliminated.” “Mitchell also recommends that the Agency consider accepting certification by a Registered Environmental Professional, as well as a Registered Professional Engineer. Either category of professional has training sufficient to evaluate the effectiveness of a SPCC Plan.” (24, 31, 67, 71, 74, 76, 85, 86, 115, 186) We should permit certification by “a degreed geologist/hydrologist with five years experience, a degreed engineer with five years experience, or a registered PE .” (70) “Facility superintendents, geologists, planners, geographers, hydrologists, and people with many other qualifications can do the work with at least the same insight and of the same quality as a PE.” (109)

Owner/operator discretion suggested. “Because the facility owner assumes all liability associated with the adequacy of the facility design and SPCC plan, the EPA should not be involved in specifying who must certify it.” (107) “Questar strongly recommends that facility owners/operators be the certifying authority for the plans (and amendments thereto) and that they be trusted to recognize their own interests and employ qualified persons to prepare the plans. If EPA rejects that suggestion, we recommend that PE certification and review be eliminated for smaller facilities.” (109)

PE unnecessary. “IPAA would like to note that if all of the components of the SPCC Plan are prescribed by regulations, there is little use in review and certification by a Registered Professional Engineer.” (31, 86, 149, 176) The PE certification requirement is “unwarranted.” PE certification would not ensure “adequate protection of the environment” and is inconsistent with other Federal emergency response plan preparation requirements -- including Resource Conservation Recovery Act (RCRA) Contingency planning requirements. (107) The Regional Administrator (RA) “usurps” the need for a PE, and we should only use the PE as a “reliable purveyor of good engineering practice unfiltered by unnecessary regulations.” (110) “...Arvin believes that tanks, piping, containment structures, and other ancillary process equipment be certified as to its integrity by a registered, independent, professional engineer. However, development of SPCC plans, etc., requires a great deal of common sense, a working knowledge of the facility, knowledge of regulatory requirements and guidelines, etc. None of these requirements indicate a need for a PE.” (162) Federal and most State hazardous waste management regulations have no requirement for a PE to develop a contingency plan. (176) PE Plan certification is unnecessary, because we already require owners or operators to follow good engineering practice. (L27)

Small facilities. “PTL agrees that a registered professional engineer (P.E.) should review and certify SPCC plans which are required for facilities that store

in excess of 42,000 gallons aboveground. We do not agree that a PE is needed to review and certify a SPCC plan which has a storage capacity less than 42,000 gallons. Our reasoning is that facilities that store less than 42,000 gallons do so with multiple tanks which typically consist of 5,000 to 10,000 gallons in capacity. These tanks are required to contain the Underwriters Laboratory Seal of Approval prior to installation. Moreover, state and local fire marshal's office require detailed plans be submitted to their office prior to installation of these systems. Therefore, it does not seem cost effective to have a registered engineer develop a plan to ensure the integrity of these systems that have already been scrutinized by state and local agencies." (82,109,124,166)

Applicability of requirement. We should insert in §112.3(d) language "to convey the thought that the P.E. certification pertains only to compliance with SPCC requirements...." (8)

No State registration. "American Samoa is a Territory of the United States located in the South Pacific approximately 2,400 miles from the State of Hawaii, with a population of approximately 47,000. As a result, the Government of American Samoa does not register Professional Engineers. Therefore, compliance with the proposed SPCC certification would be impossible." (L21)

Certification eligibility. "It appears that any registered engineer can certify a Plan. Most states, if not all, have rules of professional conduct that prohibit licensees from engaging in work the engineer is not competent or qualified to perform by reason of education, training, or experience." (L25)

Dates, status, etc. "The certification attesting to an examination of the facility by the PE should include the date(s) of the examination and the topics addressed during the examination, and the status of construction and other site preparations as of the date(s) of the examination." (43)

Editorial clarifications. "The term 'Registered' is not used in the Michigan Professional Engineer (PE) Act, and perhaps in other states as well, inasmuch as PEs are now 'licensed' rather than registered to practice engineering. Thus I recommend that the word 'Registered' be deleted wherever it is used immediately before the words 'Professional Engineer' in this regulation...." (43) We should clarify the rule language by stating "that the Engineer shall attest that...he/she has examined the facility." (121)

Knowledge, information, and belief. We should clarify in §112.3(d) that in certifying a Plan, the PE makes the §112.3(d) attestations "to the best of the Engineer's knowledge, information, and belief." (24)

Liability. We should amend the rule to protect a PE from legal liability for performance under §112.3(d), except for gross negligence or willful misconduct. Because we do not require PE certification for the facility design, a PE may certify a poorly designed facility. (24)

PE Audit. We should require a PE audit the facility just before a facility begins operation to determine whether “all elements of the SPCC Plan are in place” and whether “the facility’s personnel have been trained to deal with spills.” (43)

State registration laws. We should solicit information from the National Council of Examiners for Engineering and Surveying (NCEES) on State variations in PE registration laws to help modify part 112. (26)

Time limit for PE certification. “A time limit of less than three (3) years should be placed on the validity of the PE’s certification. EPA should require that the PE reinspect the premises periodically, preferably annually, to ascertain that the SPCC Plan continues to be fully implemented.” (43)

Existing certifications. Requests “that it be clarified that existing SPCC plans are grandfathered from the PE visitation/recertification requirements until plan updates are required.” (167)

Response: *Support for certification requirement.* We appreciate commenter support for the PE review and certification requirement. PE certification of all facilities, both large and small, is necessary because a discharge as described in §112.1(b) from any size facility may be harmful, and PE review and certification of a Plan may help prevent that discharge. Because a Plan for a smaller facility is likely to be less complicated than a Plan for a larger facility, PE certification costs should likewise be lower for a smaller facility. In our Information Collection Request, estimated total costs for a new facility to prepare and begin implementation of a Plan, including PE certification costs, are \$2,201 for a small facility, \$2,164 for a medium facility, and \$2,540 for a large facility. This cost is incurred only in the year that the facility first becomes subject to the rule. This one-time cost incurred by a small facility is less than 1.5 percent of the average annual revenue for small facilities in all industry categories. The cost for the PE certification alone would represent even less than that. As shown in Chapter 5 of the Economic Analysis for this rulemaking, the average annual revenue for the smallest regulated facilities (under the current rule) ranges from \$150,000 to \$6,833,000, depending on the industry category. For example, farms with annual revenue between \$100,000 and \$249,999 have an average annual revenue per farm of \$161,430, and \$2,201 (the one-time cost to prepare and implement a Plan) represents only 1.36 percent of that annual revenue. Of course, under the revised rule many of these small facilities will not be regulated by the SPCC program at all.

A PE’s certification of a Plan means that the PE is certifying that the facility’s equipment, design, construction, and maintenance procedures used to implement the Plan are in accordance with good engineering practices. And this is important because good engineering practices are likely to prevent discharges. PE certification, to be effective for SPCC purposes, must be completed in accordance with the law of the State in which the PE is working. For example, some States require a PE to apply his seal to effectuate a certification. Others do not.

We disagree that the Regional Administrator (RA) “usurps” the need for a PE. The RA does not review or certify an SPCC Plan, as does the PE. Therefore, there is no overlap between RA and PE responsibilities in the SPCC Program. The PE is crucial to designing a facility-specific Plan for each facility that accords with good engineering practice. His certification is necessary to document that the Plan was prepared in accordance with good engineering practice.

We also disagree that small facilities need not have PE certification for SPCC Plans when the tanks are certified by the Underwriters Laboratory. A Plan consists of more than a certified tank. It contains provisions for secondary containment, integrity testing, and other measures to prevent discharges. Those provisions require PE certification to ensure that they meet the requirements of the rule and that the Plan is effective to prevent discharges

Applicability of requirement. We reaffirm that PE certification requirement in part 112 pertains only to compliance with SPCC requirements.

No State registration. In response to the commenter from Samoa, who noted that territory does not register PEs, the rule would allow an SPCC facility there to hire a PE licensed in some other State or U.S. territory.

Dates, status, etc. The certification must be dated because the date is necessary to detail compliance with Plan implementation requirements. We disagree that the attestation need contain examination dates, topics addressed, and status of construction and other site preparations. Those items are more appropriately addressed in the Plan itself or for a log or appendix to the Plan.

Editorial clarifications. *Editorial clarification.* No editorial change is necessary because the owner or operator is already required to make the Plan available for on-site review. See §112.4(d).

We agree that the correct term is “licensed Professional Engineer,” rather than “Registered Professional Engineer,” and that is the term we use in the rule.

Knowledge, information, and belief. We agree that the PE attests “to the best of his knowledge, information, and belief,” but do not believe that additional rule language is necessary because the language is already implicit. We note that the attestation requires no specific formula, merely documentation of compliance with the required elements.

Liability. We disagree that we should amend the rule to protect a PE from legal liability for performance under §112.3(d), except for gross negligence or willful misconduct. PE liability, is and should remain, a matter of State law.

Other environmental professionals. Certification by a PE, rather than by another environmental professional is necessary to ensure the application of good engineering judgment. Likewise, we disagree that we should permit an owner or operator to certify the Plan and technical amendments, or that we should eliminate PE Plan review and certification for smaller facilities. As described above, PE certification helps ensure the application of good engineering practice. We agree that a PE should be qualified by education, training, or experience, and note that “most States prohibit licensees from engaging in work the engineer is not competent or qualified to perform.” A PE must obtain a Bachelor of Engineering degree from an accredited engineering program, pass two comprehensive national examinations, and demonstrate an acceptable level (usually four additional years) of engineering experience. A licensed engineer is also required to practice engineering solely within his areas of competence and to protect the public health, safety, and welfare. We also believe that prescribing the credentials for a PE should be a matter of State, not Federal law. Licensing criteria may differ somewhat among the States. All licensed PEs, no matter who their employer, are required by State laws and codes of ethics to discharge their engineering responsibilities accurately and honestly. Furthermore, State governments have and do exercise the authority to discipline licensed PEs who fail to comply with State laws and requirements. Other environmental professionals may not have similar expertise nor be held to similar standards as the licensed PE.

PE Audit. We also disagree that we should require a PE audit the facility just before a facility begins operation to determine whether “all elements of the SPCC Plan are in place” and whether “the facility’s personnel have been trained to deal with spills.” Those tasks are the responsibility of the owner or operator, not the PE. PE certification does not relieve an owner or operator of a facility of his duty to prepare and fully implement the Plan in accordance with part 112 requirements. 40 CFR 112.3(d)(2).

State registration laws. We disagree that we should solicit information from the National Council of Examiners for Engineering and Surveying (NCEES) on State variations in PE registration laws to help modify part 112 because such information is not necessary to the implementation of the SPCC program. PE registration, is and should remain, a matter of State law. PE certification, to be effective for SPCC purposes, must be completed in accordance with the law of the State in which the PE is working. For example, some States require a PE to apply his seal to effectuate a certification. Others do not.

Time limit for PE certification. We disagree that there should be a time limit on PE certification because the rule ensures that the PE reviews the Plan at appropriate times. We also disagree that we should require periodic PE reinspection of a facility. Thus, current PE certifications remain valid. But new certifications after the effective date of this rule must include the required attestations. If you are an owner or operator you must review your Plan at least every five years (under revisions made in today’s rule), and amend it if new technology is warranted. Also, you must amend your Plan to conform with any applicable rule requirements, or at any time you make any change in facility design, construction, operation, or maintenance that materially affects its

potential for a discharge as described in §112.1(b). All material amendments require PE certification. Therefore, because a Plan will likely require one or more amendments requiring PE review and certification, a time limit on PE certifications is unnecessary. See §112.5(c).

VI - D: Whether the certifying PE may be a facility employee or have any direct financial tie to the facility - §112.3(d)

Background: In the 1991 preamble, we requested comments on whether the certifying PE should be an employee of the owner or operator, or have “any other direct financial interest in the facility.” The rationale for this proposal was to avoid conflicts of interest or the appearance of a conflict of interest between a facility owner or operator and the PE.

Comments: *Support for independent PE.*

Conflict of interest. “I believe that specially with SPCC planning and implementation is valuable for the certifying P.E. not to be an employee of the company so that he can be more objective and thus help in arriving at decisions which will help assure that the objectives of this regulation are achieved.” (21, 121, 142, 168, and L8) “On the other hand the employee engineer may be reticent because of job position or other reasons about recommending major facility modifications, if these are determined to be necessary during development or review of a plan.” (16, 21, 121, 142, 158, L8)

More economical. “Also, many companies are now finding that it is more economical to engage a SPCC trained and competent P.E. who is not an employee, rather than train an employee in the requirements specified by the SPCC regulations.” (21)

More objectivity. “I believe that specially with SPCC planning and implementation it is valuable for the certifying P.E. not to be an employee of the company so that he can be more objective and thus help in arriving at decisions which will help assure that the objectives of this regulation are achieved. The private practice P.E. can, without fear of losing his pension, benefits, job, etc., be an objective and cooperating individual who assists the owner and the regulating agencies and thereby satisfies his duties more comfortably of serving the public.” (21, 168, L8)

Opposition to independent PE requirement.

Ethics. “To suppose that a facility employee would break the law and jeopardize his license to practice his profession and do it more willingly than an ‘independent’ engineer has no basis in fact and is perhaps diametrically opposed to real world realities.” “Regarding financial interest, an independent engineer may have just as great, if not more, financial interest in accommodating the facility operator/owner.” (5, 6, 9, 14, 15, 16, 23, 24, 31, 34, 35, 36, 39, 40, 41, 51, 52, 54, 56, 58, 59, 67, 71, 72, 74, 80, 88, 90, 92, 96, 98, 103, 105, 110, 113, 114, 115, 117, 125, 126, 131, 133, 135, 136, 141, 143, 146, 155, 161, 165, 167, 170, 173, 175, 180, 181, 183, 184, 189, 190, L4, L9, L15, L19, L20, L25, L30, L31, L32)

Enforcement mechanisms.

EPA enforcement. “EPA can also take enforcement action for false certifications.” (35) “EPA should adopt an enforcement policy for taking action against the licence of a PE if the performance of the PE is not consistent with professional standards, or is negatively biased by the PE’s relationship to an operator.” (52) “Abuses of the certification function should be subject to administrative fines just as are other violations of the rules. This is a better method of ensuring proper certification, rather than trying to limit the use of all employee PEs.” (71, 96)

State law. “State laws and regulations establish adequate complaint procedures and penalties for violations of the standard of practice to which Professional Engineers are held.” (5) “EPA should not legislate in areas of state concern, such as requirements that constitute appropriate engineering practices.” (35) “Professional engineers are registered by state engineering boards, which are responsible for overseeing their ethics and technical qualifications. As a result, all professional engineers are expected to uphold the same professional standards, regardless of the entity who employs them or any other direct financial interest in the facility.” (146)

Familiarity with facility. “Depriving the owner of the use of his own engineer would in many instances exclude the most qualified person from producing the plan. The result may well be that the average new plan will be inferior to those already in existence.” (5, 6, 25, 31, 38, 47, 53, 59, 62, 71, 72, 74, 75, 77, 78, 80, 86, 88, 89, 90, 92, 98, 101, 105, 112, 116, 124, 133, 135, 136, 137, 141, 143, 145, 146, 153, 155, 160, 161, 164, 165, 167, 173, 180, 181, 183, 191, L3, L7, L14, L15, L29)

Financial burden. “The requirement of hiring an independent engineer would also place a tremendous financial burden on facility owners. ... A further substantial source of financial burden would be in revising a plan previously written by an independent engineer.” (6, 9, 10, 27, 28, 34, 35, 38, 41, 42, 47, 48, 54, 62, 68, 71, 79, 90, 91, 93, 98, 103, 105, 110, 112, 115, 125, 134, 136, 137, 139, 141, 146, 153, 155, 160, 167, 173, 175, 181, 182, 183, 188, 190, 191, 192, L2, L3, L14, L18, L20, L29, L31)

Insurance. “We are also concerned whether an independent PE could really afford the insurance to certify his work.” (71)

Financial interest, inside and outside PEs.

Outside. “Merely by contracting with the facility to review and certify SPCC plans, the PE is engaging a financial interest in the operation.” “The premise that an employee of a facility has a financial interest in the company, but that a

consultant PE under contract to the facility does not, is incorrect. A consultant PE also receives payment from the facility for his/her work. The difference between the employee PE and the consultant PE is simply that a consultant's services are over once the service has been provided. If a consultant PE does not render satisfactory service, he/she may not be retained in the future." (6, 27, 47, 52, 76, 77, 95, 102, 116, 125, 136, 164, 165, 181, 187, 189, L14, L15)

Inside. "We believe, moreover, that the 'independent' engineer proposal ignores the fact that 'independent' engineers may also have conflicting financial interests that could lead to bias. Retained experts, after all, have a strong interest in satisfying clients in the hope of renewed retention on future company projects. A tenured company engineer may have greater job security and face less risk of dismissal for professional independence than a retained expert who has no assurance of retention on future company projects requiring engineering services." (125)

Compromise position. "Perhaps the compromise here is that the PE who certifies the SPCC Plan be required to disclose in the SPCC Plan certification his or her relationship to the facility owner, the facility improvement owner, and the facility landowner." (47)

Direct financial interest. We should clarify the definition of the phrase "other direct financial interest." (87)

Response: We agree that a proposal to restrict certification by a PE employed by a facility or having a financial interest in it would limit the availability of PEs, possibly leading to delays in Plan certification. Therefore, we will not adopt it. Nor do we favor the proposal to require the PE to disclose his relationship to the facility owner, the facility improvements owner, or the facility landowner. Such disclosure would add no environmental protection to the SPCC certification process. We agree that there are mechanisms in place to enforce ethical conduct by PEs. State licensing boards expect PEs to uphold professional standards and can discipline PEs for unprofessional conduct. State administrative action to correct abuses may be an appropriate approach. We believe that most PEs, whether independent or employees of a facility, being professionals, will uphold the integrity of their profession and only certify Plans that meet regulatory requirements. We also agree that an in-house PE may be the person most familiar with the facility. EPA believes that a restriction of in-house PE certification might place an undue and unnecessary financial burden on owners or operators of facilities by forcing them to hire an outside engineer.

Direct financial interest. Because we have not adopted a requirement for an independent PE, it is not necessary to discuss what is a "direct financial interest."

VI - E: PEs - State registration - §112.3(d)

Background: In the preamble to the 1991 proposal, we requested comments on the advantages and disadvantages of requiring a certifying Professional Engineer (PE) to be licensed in the State where the facility is located.

Comments: *Support for proposal.*

Familiarity with local rules, conditions, etc. “Familiarity with the state and local requirements related to the facilities as well as the state itself are essential for viable SPCC plans. This is particularly true in Alaska when considering our unique geography and climate.” (43, 52, 54, 77, 111, 134, 142, 143, 153, 158, 159, 185)

Implementation. If a PE *prepares* a facility Plan in a State where the PE *is not* registered, another PE who *is* registered in the State should *certify* the Plan. (159, L25)

Diligent efforts. While the certifying PE should be registered in the State where the facility is located, the owner or operator should be able to use a PE registered in another State if after the diligent efforts, the owner or operator cannot find a PE registered in the State to certify the Plan. (51)

State licensing boards. “State laws and regulations establish adequate complaint procedures and penalties for violations of the standard of practice to which Professional Engineers are held.” (4, 5, 14, 23, 40, 42, 43, 71, 72, 76, 80, 86, 121, 128, 143, 154, 173, 190, L4, L17)

Opposition to State licensing requirement.

Cost. “Additional requirements for same-state registration or financial independence of the Engineer would place a greater burden on the regulated community without providing greater benefits to the SPCC program.” (10, 15, 27, 31, 34, 48, 57, 59, 65, 68, 78, 79, 86, 87, 103, 109, 112, 116, 125, 137, 150, 160, 175, 182, 191, L3, L30)

Familiarity with State and local requirements. “Furthermore, being certified in a particular state does not necessarily mean that the engineer has significant professional experience in the state. Because many of today’s professionals are mobile and prone to transfers, it is not uncommon for a professional engineer to spend most of his working career in states other than the one where he received his certification. Also, because of reciprocal agreements between certification boards in different states, it is possible to obtain certification in a one state by virtue of having been certified in a different state. Clearly, certification in a particular state does not automatically mean that the engineer is more familiar with that state’s codes and regulations than any other professional engineer.” (9,

27, 31, 34, 36, 39, 42, 48, 54, 56, 57, 59, 62, 66, 67, 72, 78, 86, 87, 89, 90, 95, 101, 102, 103, 105, 109, 112, 114, 124, 125, 128, 130, 133, 136, 137, 143, 145, 150, 152, 160, 165, 167, 170, 173, 188, 190, 191, L29, L30, L32)

No environmental benefit. “First, requiring that the professional engineer that certifies a given plan be registered in the same state as where the facility is located provides no additional pollution prevention. The exams that are administered as part of the certification process for a professional engineer deal with engineering concepts. The vast majority of these exams are standardized and do not address state specific issues, such as codes and regulations. Therefore, certification within a given state does not necessarily mean that the engineer is more familiar with the codes and laws of that particular state.” (71, 95, 102, 114, 145, 167, 170, 173, 175, 182, L29)

State licensing boards. “A State licensing board will address the actions of an engineer licensed by that board regardless of the engineer’s location when he applies his seal.” (75, 79, 80, 95, 102, 110, 113, 136, 155, 175, 182, 184, L7, L9, L32)

Would reduce the pool of available PEs. “Because of the antiquated non-reciprocal licensing laws which exist among most of the states, it is practically impossible (and certainly not cost effective) for a professional engineer to be licensed in every state.” (15)

Response: We agree with commenters that it is unnecessary that the PE be registered or licensed in the State in which the facility is located because any abuses will be corrected by the licensing jurisdiction. We also agree that such a requirement might unnecessarily reduce the availability of PEs and increase the cost of certification without any tangible benefits. The professional liability of a PE would likely be unaffected by the place of his registration. When State law precludes a PE from applying his seal if he is not licensed in that State, the question of State registration becomes moot. However, that is not the case in every State.

We also disagree that if a PE is not licensed in the State, he will be unfamiliar with State and local requirements for the facility. Any PE may become familiar with both Federal and State and local requirements for a facility. Therefore, to require that the PE be registered in the State in which the facility is located would impose unnecessary financial burdens on the facility and would challenge the integrity of the PE. Such a requirement would also reduce the pool of PEs available for facilities.

VI - F: PEs - Site visits - §112.3(d)

Background: Under §112.3(d) of the current rule, a PE must attest that he has "examined the facility" before certifying that facility’s SPCC Plan. In 1991, we proposed to clarify that the PE must examine the facility in person.

Comments: *Support for proposal.* “The language changes in the proposed regulation clarifies the requirement that the certifying engineer must physically visit the facility. Ohio EPA agrees with this change.” (15, 27, 39, 52, 74, 75, 80, 95, 102, 121, 136, 141, 158, 161, 168, 175, L29)

Good engineering practice. “Prior to preparing or re-certifying an SPCC plan, it is agreed that a site visit is absolutely necessary. The certifying PE is able to review all aspects of the plan with local management and leave with reasonable assurance that the facility would be able to prevent and/or respond to any spill event. Spill clean-up and retention equipment should be inspected as well as response personnel training.” (15, 39, L29)

Opposition to proposal. (9, 24, 28, 35, 36, 58, 65, 67, 71, 76, 78, 82, 87, 101, 113, 115, 116, 134, 145, 165, 183, 192, L4, L15, L30)

Available documentation. “A PE is expected to have the proficiency to comprehend the requirements of the rule and assess the completeness of the plan for the facility based on available information and technical backup.” (28, 87, 101, 115, 116, 165) A PE site visit will not materially improve the Plan. The PE can use topographic maps, photographs, and other methods to make an informed decision. (87) A site visit “may not provide any better information than if the facility was required to provide a professional engineer geographical and geological information that depicts land and water within one-quarter mile of the facility boundaries.” (115) A visit is unnecessary at small facilities with adequate drawings, photos, or other documentation. (116)

Cost. “Site visits to physically examine the facility would involve additional direct cost and duplication of efforts with possibly no benefits on the overall effectiveness of the plant.” (9, 28, 36, 65, 82, 101, 145, 165, L30) The site visit cost is unnecessary if the PE is “familiar” with the facility. (36) A site visit imposes substantial additional costs since many entities use vaulted aboveground storage tanks at remote locations to support transmitter sites and backup generator sites. (65) “Many sites scattered throughout Appalachia are remote, access is difficult, and travel time expensive. This requirement places an enormous burden in terms of increasing the cost for the SPCC plan. The engineer should be able to understand the adequacy of the construction in the containment plan from the documents provided. The Registered Professional Engineer can request additional documentation if the engineer deems it so necessary.” (101, 115, 145, 165)

Electrical equipment. Due to the large number of station, “it would be impractical for the certifying PE to visit and inspect each site when preparing SPCC Plans.” (134, 183)

Multiple sites. It is difficult for the certifying PE to visit multiple facilities. (9, 39, 71, 76, 78, 101, 115, 134, 145) “Where a number of facilities at distant locations

with similar operations or belonging to the same owner are involved, the extra effort and costs for physical examination of each site may not be justifiable.” (9) *Similar facilities.* A company with multiple facilities should send PEs from sister plants or corporate headquarters to assist in the review. (39) “We also question whether a PE should visit each and every site. Pennzoil builds its new company-owned lube facilities to uniform corporate plans and makes the plans available to both franchised or other Pennzoil ‘featuring’ quick lube operations. A PE should not be required to visit each site if he knows that the facility has been built to these specifications. Rather, an exemption should be granted for similarly situated and operated facilities, provided that the PE is familiar with the basic plan (i.e., the corporate quick lube facility design or the tank battery design.” (71, 78, 145)

NSPE opinion - ethics. A recent opinion of the National Society of Professional Engineers' Board of Ethical Review on a hypothetical case involving SPCC Plan certification concluded that it was appropriate for the PE to make a certification without having visited a given facility. (24)

Off-site engineers. Off-site engineers often design a facility or structure without ever visiting the site. (192)

Plan information veracity. The burden of proving the veracity of SPCC Plan information should be on the facility owner or operator. (9)

Small facilities. We should not require a site visit for small entities. (82, 116, 134, 183) “...(D)ifferential requirements based on facility size may be valid.” We should change the rule to excuse “small” facility site visits when there is “a determination that sufficient documentation of site characteristics is available for plan certification.” (183)

Temporary storage. “The requirement that a professional engineer examine each storage ‘facility’ is similarly impractical for temporary (often mobile) storage.” (60)

Response: *In general.* EPA agrees that the rule should not necessarily require a site visit by a certifying PE, but we believe that a site visit should occur before the PE certifies the Plan. We have modified proposed §112.3(d)(ii) to reflect this position. The PE’s agent may perform the visit. We agree that customary engineering practice allows someone under the PE’s employ such as an engineering technician, technologist, graduate engineer, or other qualified person to prepare preliminary reports, studies, and evaluations after visiting the site. Then the PE could legitimately certify the Plan. Nevertheless, in all cases the PE must ensure that his certification represents an exercise of good engineering judgment. If that requires a personal site visit, the PE must visit the facility himself before certifying the Plan.

Particular cases. EPA agrees that a PE site visit requirement might be impractical at electrical substations, due to their large number. However, the PE need not go. One of his agents may go, and he may review the agent's work. We disagree with commenters who believe that a site visit is unnecessary at small facilities and temporary storage facilities. Site visits are necessary for those facilities to ensure Plan adequacy and to prevent discharges.

EPA has interpreted the current rule language to contain a requirement that the PE examine the facility. Because of the uncertainty concerning the nature of this requirement, however, we will not require documentation of a site visit by a PE or his agent until after the effective date of this rule. We disagree that the rule should only require that the PE be familiar with the operation and design of the type of facility. We also disagree that merely because the PE has visited and examined one or more facilities of a particular type that no site visit is necessary. A facility may have individual characteristics that differ from those of its type in general, and a site visit by a PE or agent may be necessary to detect those characteristics and accommodate them in the Plan. Such individual characteristics include geographic conditions, possible flow paths, facility design and construction, type of containers, product stored, particular equipment, and the integrity of containment at the facility. Therefore, even if a PE has inspected many facilities of a particular type, that fact does not eliminate the need for a site visit at each facility. After the site visit by the PE or his agent, the PE will have to devise appropriate inspection and testing standards based on the facility's unique characteristics.

Cost. We have imposed no additional burden on an owner or operator by clarifying the rule language. To mitigate costs, we allow the PE to send an agent to a site to conduct the site visit. That agent might be, for example, an engineering technician, technologist, graduate engineer, or other qualified person to prepare preliminary reports, studies, and evaluations after visiting the site. After review of the agent's work, the PE could legitimately certify the Plan.

Editorial clarifications. "Registered Professional Engineer" becomes "licensed Professional Engineer." The first sentence of the paragraph was proposed as, "No SPCC Plan shall be effective to satisfy the requirements of this part unless it has been reviewed by a Registered Professional Engineer." We revised it to read, "A licensed Professional Engineer must review and certify a Plan for it to be effective to satisfy the requirements of this part." This revision is due to the fact that PEs are licensed by States.

Inspection requirements. We agree that inspection of equipment is essential to Plan certification; training of personnel for response purposes is not required by the SPCC rule and the PE does not certify such training in his attestation.

Plan information veracity. We agree. The owner or operator has a duty under §112.3(d) to prepare and fully implement the Plan. Therefore, the facility owner or operator ultimately is responsible for providing the PE with accurate information.

Small facilities. We believe that a site visit is necessary for every facility, regardless of size, to prepare a Plan which will prevent a discharge as described in §112.1(b).

VI - G: PE Plan Certification - completion of testing procedures - §112.3(d)

Comments: *Support for proposal.* “Proposed §112.3(d) adds responsibilities to the Professional Engineer (PE) in the preparation of SPCC Plans. The PE must certify ‘that required testing has been completed.’ Alyeska supports this requirement.” (77)

Inspection. “I think it would be better for the engineer to enumerate all the inspections and tests that have been completed, plus those that should be completed before the facility commences operations and those that should be undertaken periodically after it commences operations.” (43)

Tests required. “‘Required testing’ is not explained or defined and therefore unclear. East Ohio Gas recommends ‘required inspection’.” (70)

PE presence. We should clarify whether the PE must be present during testing. (58)

Test completion. “Unfortunately much of the testing required under an SPCC Plan need not be performed before the Plan must be certified. Thus, the Engineer cannot attest to that Plan until all testing has been completed, which can take up to a year to complete. Instead of attesting to the ‘completion of required testing’, we suggest that the engineer be allowed to attest to the presence of those written procedures, which require testing. By so doing, an engineer can certify the Plan before a facility begins operations.” (33, 102) “This would appear to be an implementation activity, and should be the responsibility of the operator, not the engineer. In addition, unless the engineer is actually present at or performs the testing, his/her ability to ‘attest’ to such would be limited to a review of the results. Because these test results are to be maintained at the facility in any event, this requirement would make such an attestation redundant.” (76, 121,146)

Response: *Support for proposal.* We appreciate commenter support.

Testing. EPA agrees that the PE is not responsible for certifying that all required testing has been completed. Rather, such responsibility belongs to the owner or operator of the facility. Testing may be ongoing long after the Plan is certified. The PE is responsible for certifying that the Plan is adequate and meets all regulatory requirements, including enumeration of all tests that have been completed, plus those that should be completed before the facility commences operations and those that should be undertaken periodically after it commences operations. Therefore, we are changing the proposed requirement to a requirement in which the PE attests that the procedures for required inspections and testing have been established, and the Plan is adequate for the facility. See the discussion of §112.3(d) in today’s preamble and immediately above in this document.

VI - H: Plan location at the facility - §112.3(e)

Background: Under §112.3(e) of the current rule, an owner or operator must maintain the Plan at the facility if it is attended at least eight hours a day, or at the nearest field office if the facility is attended less than eight hours a day. In 1991, we proposed changing the eight-hour threshold to four hours to ensure that a facility operating one shift per day has a Plan on site.

Comments: *Support for proposal.* “We strongly agree with the proposed change to four hours, that a facility must be manned in order for a copy of the SPCC plan to be maintained at the facility. This will ensure that facilities that operate only one shift per day will have an SPCC plan on site. We have frequently been told by facilities that they will have to send us a copy of their plan from company headquarters when one is requested during a site inspection or spill response.” (27, 42,101, L11).

“Without advance notice.” Would add the words “without advance notice” to end of proposed §112.3(d)(2). “This change will emphasize the need to have the SPCC Plan fully implemented at all times, not just when there is notice of an impending inspection.” (43)

Opposition to proposal.

Less than four hours; inconsistent requirements. “Under 40 CFR 111.3(e)(1), the SPCC Plan may maintain a copy of the Plan at the nearest field office if the facility is attended less than four hours a day. Under 40 CFR 112.3(e)(2), however, the Plan must also be available for on-site review during normal working hours. These are mutually inconsistent when applied to a facility operating less than four hours per day. ... It is apparent from the preamble, however, that EPA expects facilities to have their Plan available at all times at the facility. Thus, we see no rationale for having the Plan maintained at the nearest field office instead of at the facility itself. We would suggest, therefore, that the Plan be maintained only at the facility and not the nearest field office.” (33).

Editorial clarification. Suggests using the following text to clarify §112.3(e). “Owners or operators of facilities subject to this part must maintain a copy of the SPCC Plan for the facility, prepared pursuant to section 112.3(a), (b), (c), at the facility if the facility is normally attended at least four hours a day. If the facility is attended less than four hours a day, a copy of the plan must be maintained at the field office nearest to the facility. The owner or operator shall make the plan available to the Regional Administrator upon demand for on-site inspection during normal working hours.” (121)

Location of Plan information. A “weather-protected (laminated)” copy of the facility diagram and response actions should always be displayed in an obvious location near the main entry of the facility, and at “appropriate control centers.” (76)

“Normal working hours.” It is unclear whether “normal working hours” in proposed §112.3(e)(2) refers to EPA working hours or the facility’s working hours. (95, 101, 102)
If “normal working hours” are our hours, then facilities staffed fewer hours than we are cannot meet this requirement. If “normal working hours” are the facility hours, then there is no problem with the requirement. (95, 102)

Response personnel. We should modify the proposal to require keeping the Plan at the nearest office with operational responsibility for the facility or at the emergency response center to ensure that response personnel have access to the Plan. (125)

State and local agencies. “LEPCs and SERCs would find it helpful to be aware of the availability of SPCC Plans and may wish to use them to augment their local and State response plans.” (L11)

Response: *Support for proposal.* We appreciate commenter support.

Nearest field office, normal working hours. The term “nearest field office” in paragraph (e)(1) means the office with operational responsibility for the facility, or the emergency response center for the facility, because those locations ensure accessibility for personnel who need to respond in case of a discharge. The term “normal working hours” in paragraph (e)(2) refers to the working hours of the facility or the field office, not EPA.

Location of Plan information. While an owner or operator may place a laminated copy of the Plan at a conspicuous place at the facility, there is no Federal requirement to do so. We do not require the owner or operator to keep the Plan in any particular place at the facility, merely “at the facility” when it is manned at least four hours a day.

Plan availability. Today we have finalized the 1991 proposal that the Plan must be available at the facility if it is normally attended at least four hours per day, or at the nearest field office if it is not so attended. A Plan must always be available without advance notice, because an inspection might not be scheduled. You are not required to locate a Plan at an unattended facility because of the difficulty that might ensue when emergency personnel try to find the Plan. However, you may keep a Plan at an unattended facility. If you do not locate the Plan at the facility, you must locate it at the nearest field office.

Less than four hours; Inconsistent requirements. We disagree that the rule provides mutually inconsistent requirements. If the facility is not attended at least four hours a day, the Plan must be maintained at the nearest field office, not the facility.

State and local agencies. You are not required to file or locate a Plan with a State Emergency Response Commission or Local Emergency Planning Committee or other State or local agency because the distribution would unjustifiably increase the

information collection burden of the rule, and not all committees or agencies may want copies of SPCC Plans. Should a State wish to require filing of a Federal SPCC Plan with a State or local committee or agency, it may do so. No Federal requirement is necessary.

VI - I: Extension of time - §112.3(f)

Background: In 1991, we proposed to allow only new facilities to apply for extensions of time to comply with the requirements of part 112. The current rule allows any facility to apply for an extension, including existing fixed and mobile facilities. The rationale for limiting extension requests to new facilities was that existing fixed and mobile facilities have had since 1974 to comply with the rule.

Comments: Amendments. “While the preamble discussion of this section mentions the requirement that plans be amended before any change is made and provides for extensions to be granted by the EPA Regional Administrator (RA) where immediate amendment of the SPCC plan is not practicable, no language to this effect could be found within the rule itself. ... Consequently, it is unclear if such requirements will apply or exactly how much time will be available to a facility to prepare an SPCC plan amendment.” (71)

Automatic extensions. “BHP has already stated its position that plans should not be required prior to beginning operations. If such a requirement is made, then extensions should be automatic upon the filing of a request for extension, so long as the request is made in appropriate form.” (33, 42, 66, 110, 133, 167, L12) A request for an extension should be considered “routine.” (155)

Plan requirements. Criticizes the proposed requirement to submit the existing Plan with each extension request, because EPA’s review of the Plan cannot practically be an element of the extension granting process. The language in paragraph (f)(3) “would be better say that a facility’s existing provisions remain in effect until they are superseded by changes proposed by the facility.” (155)

Response: Amendments. We have also added a provision for an extension of time to prepare and implement an amendment to the Plan, as well as an entire Plan. We believe that there may be cases in which an extension can be justified for a Plan amendment because the same extenuating circumstances may apply.

Automatic extensions. Automatic extension requests are not justifiable because we have extended the time within which most facilities have to prepare and implement Plans. See §112.3(a), (b), and (c). Also, under the revised rule, you may request an extension for the preparation and implementation of any Plan, or amendment to any Plan. See §112.3(f).

Plan requirements. We have broadened the scope of extension requests to any facility that can justify the request, because for every type of facility there may be cases in

which an extension can be justified. Existing fixed and mobile facilities may experience delays in construction or equipment delivery or may lack qualified personnel, and these circumstances may be beyond the control of, and without the fault of, the owner or operator. We also agree with the commenter that the submission of the entire Plan as a matter of course is unnecessary to evaluate each extension request. Therefore, we have amended the rule to provide that the Regional Administrator may request your Plan if he deems it appropriate. But we do not believe that he will always do so. It may be necessary under some circumstances. The Regional Administrator also retains discretion to request the Plan after on-site review, or after certain discharges. See §112.4(a)(9) and (d). We disagree with the commenter's proposed rewrite of the owner or operator's obligations while the request is pending because the better policy is to require compliance with the rest of the rule that is not affected by the extension request, rather than saying that the existing Plan continues in effect.

Category VII - Amendment to a Plan by the RA

VII - A: Registered agents - §112.4(a) and (e)

Background: Section 112.4 of the current rule describes: 1) the spill events for which an owner or operator must submit a Plan and other information to the Regional Administrator (RA) for review; 2) the information that must be submitted to the RA; and, 3) procedures for requiring amendments to the Plan. In 1991, we proposed several changes to §112.4. In §112.4(a), we proposed to require an owner or operator to provide the RA with the name and address of any registered agent when reporting a spill event, because a registered agent may have information that the RA needs. We also noted that the RA may need to contact the agent with further questions or send the reviewed Plan back to the agent. In §112.4(e), we proposed to continue requiring that the RA notify the facility owner or operator and the registered agent, if any, if the RA is proposing an amendment to the SPCC Plan. We withdrew the 1991 proposed revision of §112.4(a) in 1997, and substituted a new proposal without reference to a registered agent.

Comments: *Definition of “registered agent.”* “Since the term clearly has a specific meaning for EPA, it should either be added to 40 CFR 112.2 or specified within the preamble to the final rule. We would suggest EPA include this term in 40 CFR 112.2 since this individual has specific responsibilities under 40 CFR 112.4.” (33)

Notice to facility and agent. We should send the §112.4 notice directly to the affected facility and the registered agent. For a large railroad, it may take days for the affected facility to receive a notice given to a registered agent. (57) “The only way EPA can do this is by having the owner or operator notify EPA of the name and address of the registered agent.” (121)

On-site personnel. Because the registered agent would not know the facility SPCC Plan as well as on-site personnel, the RA should contact the on-site safety and environmental coordinator with questions concerning the Plan. (10)

Response: We withdrew the 1991 proposal that the owner or operator supply the name and address of any registered agent to the RA because we do not always need the information, and may request it when we do. We will notify the registered agent of a corporation if we know who he is.

The §112.4(e) notification requirement for registered agents now tracks the notification requirement for registered agents in §112.1(f). In §112.4(e) of the final rule, we have adopted a requirement that when the RA is requiring a Plan amendment, he must notify the owner or operator and any registered agent, if the registered agent is known.

We also will notify the registered agent, if known, of the RA’s determination in §112.1(f) that the facility owner or operator must prepare and implement a Plan. However, because we have not adopted the requirement that an owner or operator submit the

registered agent's name and address to the RA, we may not know of his registered agent. Likewise, we have no way of knowing who is the on-site safety and environmental coordinator. Therefore, we cannot notify him.

Definition of "registered agent." The concept of "agency" and "agent" is well-known in the law. Therefore, no definition of "registered agent" is necessary in these rules.

VII - B: Discharge reports to EPA - §112.4(a)

Background: Section 112.4 of the current rule describes the discharges for which a facility owner or operator must submit the Plan and other information to the Regional Administrator (RA) for review, the information that must be submitted to the RA, and procedures for requiring amendments to the Plan. In the 1991 proposed rule, we proposed several changes to §112.4. In the 1991 proposed rule, we suggested several changes to §112.4. Proposed §112.4(a) provided that whenever an SPCC facility discharges more than 1,000 gallons of oil in a single spill event, as described in §112.1(b), in two spill events within a consecutive twelve month period, the owner or operator must submit to the RA certain information.

In §112.4(a)(10), we proposed to require that an owner or operator submit to the RA information on the nature and volume of oil spilled, in addition to the information currently required under §112.4(a) because this information would help the RA identify problem areas where additional regulatory emphasis may be needed. Section 112.4(a)(13) would require the owner or operator to provide "such other information as the RA may reasonably require pertinent to the Plan or spill event."

In 1997, we withdrew the 1991 proposal for §112.4(a) and substituted a new proposal.

Comments: *Support for proposal.* We should require a report within a reasonable time period on the amount of product recovered during cleanup. (44)

Amount spilled, proposed §112.4(a)(10). Supports a requiring notification of "the nature and volume of oil spilled." (185, 193)

Compliance with proposed requirement difficult. It may be impossible to retrieve oil after a spill to test its composition and quantify "exactly" what and how much was spilled. (92, 155, L12) Violating so imprecise a requirement would subject the violator unjustly to Clean Water Act penalty provisions. (L12)

Date and year of initial facility operation. There is no purpose in providing the date and year of initial facility operation to the RA every time a spill occurs, and suggested we delete the requirement. (33)

Discharges to soil. "The rule should be altered so that it is unambiguous in indicating that all spills of the threshold amounts will trigger the need to alter the SPCC Plan." A spill to soil, "poses a risk to surface water, even if the immediate impact is only on soil

or groundwater.” Noting that SPCC Plans cover “only one 661 gallon above-ground storage tank. Amendment of the SPCC Plan for such a facility will never be required even if the tank bursts every day, releasing all of its contents onto dry soil. Surely the intent of this regulation is not to deem such spills as routine.” (43)

Failure analysis. The term “failure analysis” in §112.4(a)(9) is ambiguous and we should define it. (28, 58, 101)

“Other” information, proposed §112.4(a)(13). Section 112.4(a)(13) is “overly broad and violates due process.” (58)

Threshold for §112.4(a).

100 gallons, single event. We should decrease the quantity of oil spilled during a spill event to trigger §112.4 applicability to 100 US gallons for a single event. A 100 gallon spill is a significant spill event, and we should not permit an owner or operator to defer amending a Plan “in the presence of smaller spill events.” (43)

25 barrels single event, 50 barrels two events. The trigger should be a single spill greater than 25 barrels or two spills of 50 barrels or more within twelve months. Unless we set a “*de minimis*” amount for two spill events, an owner or operator would have to submit “a considerable amount of information” for all spills – even spills of “a few drips.” (187)

100 barrels single event, 50 barrels two events. “API recommends that EPA change the requirement to one single spill event of more than 100 barrels or two spills of more than 50 barrels each in any consecutive twelve month period. There are numerous large oil fields in the coastal area which have an extensive network of flowlines, well jackets, and platforms. Even with all the precautions taken, it would not be unlikely for more than one spill of a *de minimis* size (e.g., less than one ounce of oil) to occur in one day. Under these proposed requirements, the O/O would have to spend valuable resources filling out paperwork and reporting to EPA rather than trying to prevent reoccurrence.” (67, 91, 173)

Response: *Support for proposal.* We appreciate commenter support. We withdrew the proposal for §112.4(a) in the proposed 1997 rule and substituted new language for that section.

Date and year of initial facility operation. In 1997, we withdrew the 1991 proposal for §112.4(a) and substituted a new proposal. We agree that it is an undue burden on an owner or operator to submit information on the date and year a covered facility began operations. That information is not always necessary in order to accurately assess the discharge or to require appropriate action. When it is necessary, the Regional Administrator may request it. Therefore, we have eliminated the requirement to always submit such information after certain discharges.

Discharges to soil. We have never proposed such a requirement for SPCC purposes. The purpose of the Act is to prevent discharges as described in §112.1(b), not discharges onto soil. A spill of oil onto soil may or may not ever become such a discharge.

Failure analysis. “Failure analysis” means a study of the equipment or procedures to understand the reasons why such equipment or procedures did not function properly. The methods of such analysis should be determined according to industry standards.

“Other” information, proposed §112.4(a)(13). We disagree that proposed §112.4(a)(13), §112.4(a)(9) in the final rule, is overly broad or violates due process. EPA has authority under sections 308 and 311(m) of the Clean Water Act to require an owner or operator to provide information concerning requirements of the Act.

Threshold for §112.4(a). We agree that a higher threshold of reporting discharges is justifiable because we believe that only larger discharges should trigger an EPA obligation to review a facility’s prevention efforts. We also agree that a higher threshold should trigger a facility’s obligation to submit information and possibly have to take further prevention measures. Therefore, we have changed the threshold for reporting after two discharges as described in §112.1(b). Under the revised rule, if you are the owner or operator of a facility subject to this part, you must only submit the required information when in any twelve month period there have been two discharges as described in §112.1(b), in each of which more than 42 U.S. gallons, or one barrel, has been discharged. The other reporting threshold of 1,000 gallons in any a single discharge as described in §112.1(b) remains the same.

We disagree that a sheen caused by a discharge as described in §112.1(b) over the threshold amount that disappears within 24 hours should not require submission of information. The discharge itself may indicate a serious problem at the facility which needs to be corrected. The discharge report may give us the information necessary to require specific correction measures.

VII - C: General/other - §112.4

VII-C-1 Supplying discharge information to the States - §112.4(c)

Background: Under §112.4(c) of the current rule, an owner or operator must submit to the State *water* pollution control agency or agencies, a copy of the information submitted to the RA under §112.4(a). In 1991, we proposed to require that an owner or operator submit the information to the State *oil* pollution control agency or agencies.

Comments: *Support for proposal.* “The proposed change in section 112.4(c), which requires the operator to send a copy of the information provided the Regional Administrator to the State agency in charge of oil pollution control rather than the

agency in charge of water pollution, is helpful.” “...(I)n Texas, as in other States, more than one agency has statutory jurisdiction over oil pollution control.” (76, 99, 193)

Authority. “USEPA does not have authority under the Clean Water Act to require an owner of a facility to file a copy of the sixty day report with the responsible state agency and therefore this requirement is unlawful. USEPA should remove this requirement.” (58)

Duplicative requirement. “Operator should not be required to forward this information to a state agency also. If EPA is to regulate the SPCC, this requirement is redundant and serves no purpose.” (28, 101) “We disagree with the agency proposal that owners or operators be required to furnish the Regional Administrator with information. If the owner or operator provides a copy to the state agency in charge of oil pollution control, we believe this to be sufficient. The majority of states review the plan and submit written suggestions or improvements, etc. Submission of additional paperwork to the Regional Administrator is not consistent with the Paperwork Reduction Act as well as it would not serve any useful purpose.” (82)

Editorial comment. We should require sending the information to the appropriate “agency or agencies.” (99)

EPA guidance. We should tell each owner or operator which State agency should get §112.4(a) information. (76)

Financial assistance. States cannot participate in reviewing §112.4(a) information without financial assistance. We should “consolidat(e) programs to eliminate duplicate agency involvement.” (111)

Required Plan amendments. We should specify that only the RA may require an Plan amendment – even if a State makes recommendations. We should clarify the regulatory text to avoid this ambiguity, adding that, “EPA may require implementation of State agency recommendations only if they are within the scope of the regulations. State agencies receiving incident reports should review the reports in the context of the incident at hand and use this information for its intended purpose of advising the RA on possible amendments to the Plan.” (83)

State water control agencies. The appropriate agency to receive information is the State water control agency, and that sending information to the oil pollution control agency would “most likely mislead an operator, the public, an officer of the court and/or EPA itself.” (L12)

Response: *Support for proposal.* We appreciate the comment supporting our proposal to send §112.4(a) discharge information to the State oil pollution control agency or agencies.

Legal authority. We have ample legal authority to finalize this rule. A similar rule has been in effect since 1974. Section 311(j)(1) of the CWA authorizes the Federal government (and EPA through delegation) to establish “procedures, methods, and equipment and other requirements for equipment to prevent discharges of oil....” Section 112.4(c) of this rule is a procedure to help prevent discharges that fall within the scope of that statutory provision. It enables States to learn of discharges reported to EPA and to make recommendations as to further procedures, methods, equipment, and other requirements that might prevent such discharges at the reporting facility.

We can only implement State agency suggestions that are within the scope of our authority under section 311 of the CWA.

In general. The commenter is correct that the SPCC program is a Federal program, but we believe that in working with the States, we can improve the Federal program through coordination with State oil pollution prevention programs. Therefore, we believe that the information provided to States is neither redundant nor unnecessary. Nor is the section misleading; it clearly states the obligation of the owner or operator.

State agency review. We modified the 1991 proposal on the commenters’ suggestion to include notice to any appropriate State agency in charge of oil pollution control activities, since there may be more than one such agency in some States and all may have need for the information. We do not list such agencies in the rule, as a commenter suggested, because the names and jurisdiction of the State agencies are subject to change. It is the reporter’s obligation to learn which State agencies receive the discharge reports. Most States publish documents on an ongoing basis, similar to the Federal Register, which publicize relevant regulatory information.

We do not provide State agencies funds to review these discharge reports due to budgetary constraints. While we assume that many States review these reports carefully, we cannot require them to do so. Thus, this action is not an unfunded mandate from the Federal government to the States. But if States do review the reports, they do so at their own expense.

VII-C-2 Amendment of Plans required by the RA - §112.4(d)

Background: In §112.4(d), we proposed adding language giving the RA authority to approve a Plan after reviewing the materials submitted under §112.7(d).

Comments: *Appeals.* Asks what the procedure is for appealing an RA’s decision (on Plan approval) to the Administrator. (28, 101)

PE role in RA-required amendments. “...(A)ny ‘terms of amendment’ made by the RA must be signed and sealed by an Agency or Agency retained professional engineer.” When the RA requires a Plan amendment, “the certifying PE (has) no alternative but to certify the SPCC Plan or resign.” In such cases, EPA must certify the change as meeting good engineering practice, and “the RA must be held accountable legally and

financially” when he mandates a change that “causes or results in an oil spill.” (48, 63, 67, 72, 85, 110, 170, 173)

Plan review and approval. Proposed §112.4(d) gives the RA “unlimited authority” to reject SPCC Plans. (28, 101) We should minimize or eliminate “any activities requiring agency approvals,” given the “historical difficulty of getting dedicated resources to perform professional work related to these reviews.” (111) Having the RA approve a Plan “puts an entirely new dimension in this process,” and asked us to consider the approach. (121) “Plan review after a spill event by the EPA Regional Administrator is under the conditions identified in 40 CFR 112.4 are excessive and burdensome both to the EPA and regulated community. EPA should on a case by case basis review SPCC Plans after a spill event if the review is deemed necessary by the Regional Administrator or his/her staff.” (192)

Time limit on review. “The current language of the referenced sentence could imply that the Regional Administrator must approve or request amendments to the SPCC’s plans. In fact, the Regional Administrator does not have to take such affirmative action, unless he/she so chooses. Plan approval is not necessary for the owner/operator to continue operations of a facility. Therefore, once a plan is submitted, the owner/operator should be given a certain specified waiting period for approval, after which he/she can consider the submitted plan is adequate.” (67)

Response: *Appeals.* Because we have not adopted RA review and approval of Plans, no appeals process is necessary for a decision to reject a Plan. An appeals process exists for required Plan amendments. See §112.4(e).

PE role in RA-required amendments. A PE must certify any technical amendment to an SPCC Plan – irrespective of whether the owner or operator, or the RA, initiates the amendment process. When the RA decides a Plan amendment is necessary, it is the responsibility of the owner or operator to draft such amendment and implement it. The PE must certify that any amendment has been prepared in accordance with good engineering practice.

Plan review and approval. We have deleted the provision that would have allowed RA approval of Plans. We have decided not to create a new class of SPCC Plans which require EPA approval, either Plans submitted following certain discharges as required by §112.4(a) or Plans with contingency plans, because we do not believe such approval is necessary in order to ensure effective Plans.

Time limit on review. A time limit on RA review of a Plan is also moot because we withdrew the proposal which would have allowed RA review and approval of a Plan.

VII-C-3 Implementation of required amendments - §112.4(e)

Comments: *Implementation time for required amendments.*

“Longer than 6 months.” The rule “appears to contemplate a longer period than six months.” We should change the language to read unless the RA specifies “a longer time” in place of “another date.” (42) Six months may be an insufficient time to implement an amendment requiring new construction to the facility. (83, 143)

One year (with construction). Six months is appropriate if the change is “purely operational,” but that the implementation period should be “one year (after obtaining required permits) in a case where construction of facilities (is) required.” (83)

Extensions, reasons for. More than 6 months should be allowed for implementation if “the facility can show that the equipment, parts, etc., are not available to be installed in time, or if qualified contractors are not available to do the installation on time.” (143)

Who receives notice. We should “require that the RA provide notice to the facility operator, the facility improvement owner, and the facility landowner. The reason the expanded notice is desirable is that a major problem may be addressed by the facility operator and the EPA, without the knowledge and/or consent of the facility improvements owner and the facility landowner.” (47)

Response: In 1991, we proposed no change in the six month timeline for implementing a required Plan amendment. We agree that in some cases that six months are not sufficient to implement an amendment. We have therefore amended the rule to allow an owner or operator to petition the RA for an extension to implement an amendment. See §112.3(f)(1). Nonavailability of qualified personnel, or delays in construction or equipment delivery that are beyond the control of, and that are not the fault of the owner or operator, may justify an extension request.

Who receives notice. The rule requires notice only to the owner or operator of the facility, and the registered agent, if any and if known. Notice from EPA to the facility improvements owner and landowner is unnecessary because these matters can and should be handled between the facility owner or operator and the owner or operator of the improvements or the landowner.

VII-C-4 Appeals of required amendments - §112.4(f)

Comments: In §112.4(f), the word “decision” is ambiguous, and we should replace it with “ruling,” a less ambiguous term. (70)

Response: “Decision” is a commonly used legal term which in this context means the final determination of the RA when considering the appeal of a required amendment.

Category VIII: Amendment to a Plan by the owner or operator

VIII - A: Plan amendment by an owner or operator - §112.5(a)

Background: In §112.5(a) of the current rule, an owner or operator of a facility subject to §112.3(a), (b) or (c) must amend his Plan in accordance with §112.7 when there is a change in facility design, construction, operation, or maintenance which materially affects the facility's potential for the discharge of oil into or upon navigable waters or adjoining shorelines. An owner or operator must implement such amendment as soon as possible, but not later than six months after the change occurs.

In 1991, we proposed in §112.5(a) to require an owner or operator to amend his Plan *when* making any material changes in facility design, construction, operation, or maintenance affecting the facility's potential for discharge of oil, unless the Regional Administrator grants an extension. In the preamble we noted that an owner or operator must amend the Plan *before* making any material changes in the specified categories. We also listed examples in the proposed rule of facility changes requiring Plan amendment.

Comments: *Support for proposal.* "As with Section 112.3, we feel that this proposal has merit, because it requires plant personnel to evaluate the spill potential of their planned additions before they are built." (80, 181, L1)

Accumulation of changes. "APS proposes that language be added to allow facilities that perform minor modifications on a regular basis, be allowed to 'accumulate' those changes for a period of six months, then update the plan. In addition, APS suggest these 'minor modifications' be defined as modifications that do not need additional containment or spill prevention systems to prevent oil from reaching 'waters of the U.S.'" (74)

Alternatives to amendment.

Fractionization tank. "... (U)nless language were added to exclude fractionization tanks from the SPCC program, each time a frac tank is used or moved to a new location, a modification to the facility-specific SPCC plan would be required per 112.5(a). Frac tanks are often used to store oil for short periods of time while maintenance or workover operations are underway. The use of frac tanks is of very short duration and does not necessarily increase the potential for a discharge." (167)

Log book. Instead of amendment for standard facility activities, "BP proposes instead than an operations log book of such routine activities be maintained to document routine activities and what measures were taken to maintain the spill prevention and response integrity of the facility. Additionally, a facility status board showing the status of storage tanks, main control valves, dikes and dike drain valves, catchment basins, etc., could be posted in a prominent area to

keep all pertinent employees informed of the changing conditions at a facility.” (96)

Owner/operator review - common repairs, etc. “...(M)ost plans can accommodate many changes without amending the Plan. This would be especially true of a facility that has site-wide secondary containment. Operators should be allowed to document that they have reviewed such changes, and have either determined that an amendment to the Plan is not required, or have requested a review from the certifying PE. The PE should be allowed to document that he/she has reviewed the planned changes, and has concluded an amendment is not necessary, that further study is required, or that an amendment is required.” (76) “Pennzoil opposes any requirement that plans be amended prior to all changes to the tank structure. Pennzoil believes that flexibility, such as that provided in the current rule for amendments to SPCC plans, is essential to ensure that operators of facilities have the ability to make immediate modifications or repairs to oil piping or storage systems. ... To delay the modification until a plan can be revised and reviewed by a PE or to wait on the approval by the EPA RA of a requested extension of time could be detrimental.” (71, 113)

Material changes.

“Adverse” effect. “The standard for operation and maintenance changes should be the same as that for design and construction changes—a change that would result in a material adverse effect to the potential of a facility to discharge oil.” (35)

Clarification needed. We should clarify what it means to *materially affect a facility’s potential to discharge oil*. (96, 118, 164, 189)

Examples of material changes.

Support for EPA list. Support for proposed list of examples that may constitute a *material change* requiring Plan amendment. (102, 118, 170, L8)

Opposition to EPA list. “A strict interpretation of the proposed rule would appear to require an amendment for any such change (and possibly a site visit by the certifying engineer). This is excessive. The people entrusted to the operation of such a facility should be able to evaluate most conditions and determine if an amendment is necessary.” (76) We should narrow the examples of material changes. The list is too broad. (33, 34, 58, 75, 101, 125, 164, 165, 167, 173, L8, L12, 1155 (1993 commenter)). We should create an inclusive list of material changes. (189)

Examples are not definitive for all facilities. “API believes that the wording in Section 112.5(a) should be changed to read ‘*Examples of changes that may*

require amendment to the Plan include, but...’ While API agrees with the requirement to report facility changes that materially affect a facility’s potential to discharge oil, the examples of changes requiring amendment of the Plan would not, in most instances, materially affect a facility’s oil discharge potential. In many facilities such as refineries, the examples of changes (in the proposed regulations), requiring SPCC Plan amendment and subsequent recertification by a PE are daily occurrences.” (67, 86, 125)

Change of product. “An amendment to the SPCC Plan should also be required when there is a change in the product stored within the tank. Such amendment should address the permeability of the secondary containment system, material compatibility, etc. for the product being stored.” (111) “Changing a product in a tank or cleaning a tank should not be considered commissioning or decommissioning a tank.” (143)

Oil storage or transfer. We should clarify that only “systems and operations directly related to oil storage or transfer which may impact the environment” may require Plan amendment under §112.5(a). (62)

Piping systems. “For instance, the replacement of a piping system is listed as a type of change that would require amending the Plan. Is this true when the piping replacement is made in accordance with the same industry standards as the original, serves the same function as the original, and is replaced in exactly the same location. What about adding a new piping run to an already existing run of 6 pipes carrying similar types of materials? BP suggests that neither of these changes are ‘substantial’ but the proposed rule, as stated, could be interpreted otherwise.” (96)

Tanks over 5,000 gallons. We should replace the word *tanks* with *tanks over 5,000 gallons* in our listing of examples. (L8)

Changes which are not material.

Commissioning tanks, etc. Commissioning, decommissioning, replacement, reconstruction, or movement of tanks (28, 37, 58, 66, 71, 96, 101, 113, 164, 165, L2, L15)

Contact list. Non-technical changes to the Plan (e.g., contact list, phone numbers, names, etc.) (72, 121, 190)

Inspection documents. Non-technical changes to the Plan, such as frequency of inspection and inspection documents. (72, 76, 165, L7)

Piping systems. Reconstruction, replacement, or installation of piping systems. (28, 66, 96, 101, 113, 165, L2, L15).

Routine operation and maintenance. Revising standard operation or maintenance procedures at a facility (28, 35, 70, 101, 102, 165, 167, L6) Minor alterations or certain kinds of construction – such as replacing a pump or tank in-kind or routine valve replacements – are not material changes. (155, 164)

Revision of standard operation or maintenance procedures at a facility. We should clarify what constitutes a *revision of standard operation or maintenance procedures at a facility*. (L8)

Time line for amendment implementation.

Opposition to proposed time line. “Proposed section 112.5 would require an amendment to an SPCC Plan before there is a change in facility design, construction, operation, or maintenance of the facility that materially affects the facility’s potential to discharge oil. IFTOA believes that the proposal is too broad. Numerous design changes are proposed as facilities are evaluated. Designs are made, modified, or discarded. Requiring an amendment every time a facility design is substantially changed will subject owners and operators to significant costs, wasted efforts and inefficiencies. Only when a material change has actually been implemented, such as completion of construction, should an amendment to the Plan be required.” (54, 57, 68, 71, 75, 77, 103, 125, 155, 165, 167, 169, 170, 173, 191, L2, L15, L30)

Alternative time frames. Start-up of operations (103, 125, 155, 165, 170); after the completion of facility changes or modifications (54, 57, 75). After a design change, but before implementing that change (77); after installing new structures and equipment, but before operation (L2); and during the next triennial review (71). We should require owners or operators to amend the Plan *when* there is a material change in facility design, construction, operation, or maintenance. (75) For multi-well drilling programs, we should require owners or operators to amend the Plan *after* completing a drilling program. (167)

“Adequate time.” We should allow owners or operators of existing facilities *adequate time* for Plan amendment. (71)

30 days. Thirty days after completing new construction, and make the extant Plan temporary during that period. (37)

90 days. We should allow owners or operators of exploration and production facilities and small gas processing operations 90 days to amend the Plan following any facility change. (114)

6 months. (67, 91, 110, 113, 167, 173, 1155 (1993 commenter)). For implementing an amendment, we should allow owners or operators six months following facility changes. (35, 78, 101, 145) We should require implementing the Plan amendment within six months of a new facility’s initial operations or

additions to an existing facility. The extant Plan should be temporary during that period. (134) We should allow owners or operators six months to amend the Plan following a change that does not increase the facility's oil discharge potential, but require a Plan amendment *before* a change that increases oil discharge potential. (190)

Emergencies. The implementation time line could be detrimental in an emergency, because an owner or operator could not make immediate facility modifications or repairs without first amending the Plan. (71, 191)

When amendment is necessary.

Changes consistent with existing Plan. We should not require amendment of SPCC Plans for facility changes consistent with the existing Plan. (31, 86, 160, 1155 (1993 commenter))

Changes in discharge potential. We should require Plan amendment for replacing equipment only if the facility's oil discharge potential is materially changed. (31, 160)

Decrease in discharge potential. We have no environmental justification for imposing amendment costs when owners or operators make changes that decrease a facility's discharge risk. (125)

Increase in discharge potential. "APC recommends the wording in this section reflect an amendment is required, whenever a facility's potential for discharge of oil is changed or increased. The removal of equipment decreases the facility's potential and appropriate documentation should be placed in the Plan and be amended during the three year review process." (25, 35, 66, 71, 72, 98, 101, 118, 125, 167, L12)

Changes "significantly impacting the environment." We should require owners or operators to amend the Plan only for changes that can significantly impact the environment. (L8)

Changes warranting amendment. "We recommend that current SPCC Plans be allowed to remain intact as currently written until changes occur to existing oil storage facilities which warrant SPCC Plan amendments." (79)

"Indicia of problems." Amendments should be made "when there are indicia of problems." (43)

Response: *Support for proposal.* We appreciate commenter support.

Accumulation of changes. An owner or operator must amend the Plan *when* there is a material change at a facility. Therefore, he may not *accumulate* material changes for six months before amending the Plan.

Alternatives to amendment. We disagree that owner/operator review of facility changes is a substitute for Plan amendment. When no amendment is required because there is no material change, there is nothing to do. When amendment is required, it must be certified by a PE. We distinguish this review situation from the technological review mandated under §112.5(b). Under that provision, the owner or operator may certify that there has been a review and that he will not amend the Plan as a result.

Log book. We agree that an owner or operator may document routine activities in an operations log book rather than require a Plan amendment. However, in the event of a material change at a facility, a log book entry is no substitute for Plan amendment.

Material changes. We appreciate commenter support for our proposed examples of facility changes that constitute a *material change*. A material change is one that may either increase or decrease the potential for a discharge. We believe that an amendment is necessary when a facility change results in a decrease in the volume stored or a decrease in the potential for an oil spill because EPA needs this information to determine compliance with the rule. For example, the amount of secondary containment required depends on the storage capacity of a container. We agree with the commenter that the rule should be worded to indicate that the examples are for illustration only, because the items in the list may not always trigger amendments, and because the list is not exclusive. Only changes which materially affect operations trigger the amendment requirement. Ordinary maintenance or non-material changes which do not affect the potential for the discharge of oil do not.

We disagree that decommissioning of a container that results in permanent closure of that container is not a material amendment. Decommissioning a container could materially decrease the potential for a discharge and require Plan amendment, unless such decommissioning brings the facility below the regulatory threshold, making the preparation and implementation of a Plan no longer a requirement. We also believe that the oversight of a Professional Engineer is necessary to ensure that the container is in fact properly closed.

We agree that replacement of tanks, containers, piping, or equipment may not be a material change if the replacements are identical in quality, capacity, and number. However, a replacement of one tank with more than one identical tank resulting in greater storage capacity is a material change because the storage capacity of the facility, and its consequent discharge potential, have increased. The addition of a new piping run to an already existing run of 6 pipes carrying similar types of materials may likewise be a material change because it may reflect a change in storage capacity or may affect the integrity of the secondary containment system.

Changes of product. We have added to the list of examples, on a commenter's suggestion, "changes of product." We added "changes of product" because such change may materially affect facility operations and therefore be a material change. An example of a change of product that would be a material change would be a change from storage of asphalt to storage of gasoline. Storage of gasoline instead of asphalt presents an increased fire and explosion hazard. A switch from storage of gasoline to storage of asphalt might result in increased stress on the container leading to its failure. Changes of product involving different grades of gasoline might not be a material change and thus not require amendment of the Plan if the differing grades of gasoline do not substantially change the conditions of storage and potential for discharge.

A change in service may also be a material change if it affects the potential for a discharge. A "change in service" is a change from previous operating conditions involving different properties of the stored product such as specific gravity or corrosivity and/or different service conditions of temperature and/or pressure. Therefore, we have amended the rule to add "or service" after the phrase "change of product."

Revision of standard operation or maintenance procedures at a facility. A revision of a standard operation or maintenance procedure is a change in such operation or procedure that may materially affect the facility's potential for discharge. If it does, it must be the subject of an amendment to the Plan.

Time line for amendment implementation. We agree with commenters that we should not require Plan amendment before material changes are made. Therefore, we have revised the proposed rule to provide a maximum of six months for Plan amendment, and a maximum of six more months for amendment implementation. This is the current standard. We note that §112.3(f) allows the RA to authorize an extension of time to prepare and implement an amendment under certain circumstances.

When amendment is necessary. We agree with the commenter who suggested that we maintain the current standard for amendments, i.e., when there is a change that materially affects the facility's potential to discharge oil. This position accords with our stance on when Plans should be prepared and implemented. See §112.3. The other suggested standards too narrowly limit the changes which would trigger Plan amendment. We believe that an amendment is necessary when a facility change results in a decrease in the volume stored or a decrease in the potential for an oil spill because EPA needs this information to determine compliance with the rule. For example, the amount of secondary containment required depends on the storage capacity of a container. Decreases might also affect the way a facility plans emergency response measures and training procedures. A lesser capacity might require different response measures than a larger capacity. The training of employees might be affected because the operation and maintenance of the facility might be affected by a lesser storage capacity.

Likewise, a standard requiring amendment “when there are indicia of problems” is too vague and leaves problems unaddressed which may result in a discharge as described in §112.1(b). A standard requiring an amendment only when the change would cause the spill potential to exceed the Plan’s capabilities (because day-to-day changes do not affect the worst case spill) would have the effect of leaving no documentation of amendments which might affect discharges which do not reach the standard of “worst case spill.” While we encourage facilities to incorporate new procedures into Plans which would help to prevent discharges, amendments are still necessary when material changes are made to document those new procedures, and thus facilitate the enforcement of the rule’s requirements. We disagree that a small facility should be exempt from making amendments for material changes. Amendments may be necessary at large or small facilities alike to prevent discharges after material changes.

Tanks over 5,000 gallons. We decline to apply the §112.5(a) material change requirement only to tanks or containers over 5,000 gallons. A small container may be the source of a discharge. Therefore, preventive measures are necessary for such containers, including Plan amendments.

VIII - B: Periodic review of plans - §112.5(b)

Background: Under §112.5(b) of the current rule, the owner or operator of a facility subject to §112.3(a), (b), or (c) must complete a review and evaluation of his SPCC Plan at least once every three years from the date his facility becomes subject to part 112. He must amend the SPCC Plan within six months of the review to include more effective prevention and control technology if such technology will significantly reduce the likelihood of a spill event from the facility, and if such technology has been field-proven at the time of the review.

In the 1991 proposal, we requested comments on whether a facility owner or operator should affix a signed and dated statement to the SPCC Plan indicating that the triennial review has taken place and whether the Plan requires amendment. We did not propose a change in rule text in 1991, but in 1997 we proposed to require the owner or operator to certify completion of the review. We also proposed in 1997 to change the three-year review cycle to a five-year review cycle. We address the comments received on the 1997 proposal in the Response to Comments document for the 1997 proposal.

Comments: *Support for proposal.* “Without this requirement, we feel that many companies would claim to have reviewed their plan when they had not.” (10, 27, 62, 74, 95, L17).

Opposition to proposal. “The requirement would be extremely costly and unnecessary. (28, 31, 37, 54, 83, 86, 101, 143, 160) If a Plan is submitted and approved, we should require no further changes. (28, 101)

Case-by-case basis. “The requirement proposed at subsection (b) should be deleted. If necessary, they could be applied on a case by case basis to facilities

determined by the Agency to present a high risk of catastrophic failure. In no case should they be applied to all facilities subject to SPCC Plan requirements.” (31, 86, 160)

Lack of oversight. We cited no evidence of an increased number of spills from SPCC-regulated facilities due to a lack of managerial oversight. There is no evidence that more managerial oversight would improve the quality and effectiveness of an SPCC Plan. (31, 34) This provision would be redundant and would result in an unnecessary paperwork increase. (25, 155, 190, 192)

Owner/operator discretion. “This rule should remain flexible and be implemented at the discretion of the facility owner/operator. If EPA believes that a technology should be adopted by industry, it should announce it in the *Federal Register*, hold a public hearing, and consider all the arguments for and against imposing the requirement.” (143)

PE input. “Accordingly, IFTOA recommends that amendments to the SPCC Plan be made following triennial review and evaluation if the Registered PE, after his review of the new technology and a cost benefit analysis, informs the company that changes should be made. Thus, good engineering practices rather than ‘speculation’ about new technology will be the underlying basis for any amendment.” (54)

Production facilities. “Applying such a requirement to typical oil and gas production operations could cause premature abandonment of valuable reserves by imposing potentially high investment requirements on facilities which by nature produce a decreasing revenue stream over time. Given the low risk from the typical oil and gas production operation, such a requirement is unjustified.” (31, 86)

Field-proven technology. We should clarify the term *field-proven technology*. (35, 27)

Who performs the review. “Professional Engineers, not facility owners and operators, should complete the three-year SPCC Plan review and evaluation to determine if the facility is in compliance with relative industry standards as well as federal and state rules and regulations. Most owners, if left to their own discretion, will not voluntarily say or realize that their facility is not in compliance. This puts a greater burden on the regulating community to verify facility compliance.” (111)

Documentation of review. We should require owners or operators to affix a signed and dated statement to the Plan stating that the review has taken place, and indicating whether an amendment to the Plan is necessary. (121)

Response: *Support for proposal.* We appreciate commenter support. We note that we do not routinely require an owner or operator to submit the Plan nor do we approve Plans. We decline to grant the owner or operator discretion to decide whether or not to conduct the review. This provision is important for all regulated facilities, large and

small, because modern technology is dynamic, and a responsible owner or operator should periodically assess whether the latest field-proven technological advances could decrease the facility's oil spill potential.

Documentation of review. We agree that we should require an owner or operator to affix a signed and dated statement to the Plan stating that the review has taken place, and indicating whether an amendment to the Plan is necessary. See the 1997 Response to Comments Document for further discussion of this issue.

Time line for amendment implementation. We agree with commenters (see comments on proposed §112.5(a)) that the preparation and implementation of Plan amendments require more time than proposed. The same rationale applies to the preparation and implementation of amendments required due to five-year reviews. Therefore, we will require adherence to the time lines laid down in §112.5(b) for amendments. Currently, §112.5(b) requires that Plan amendments be prepared within six months. It is silent as to timelines for implementation. Therefore, we have revised the rule to clarify that amendments must be implemented as soon as possible, but within the next six months. This is the current standard for implementation of certain other amendments. See, for example, §§112.3(a) and 112.4(e). We note that §112.3(f) allows you to request an extension of time to prepare and implement an amendment.

Field-proven technology. *Field-proven technology* means that the technology has been validated in a setting typical of everyday use.

VIII - C: PE certification of technical amendments - §112.5(c)

Background: Under §112.5(c) of the current rule, a Professional Engineer (PE) must certify any amendment to an SPCC Plan in accordance with §112.3(d). We proposed to modify this provision in 1991 to require that a PE must certify all amendments to the Plan except for the contact list required by §112.7(a)(3)(ix).

Comments: *Support for proposal.* Allowing changes to the contact list without PE certification makes sense and results in cost savings for facilities. (23, 27, 88, 103)

PE certification. The §112.5(c) requirement to certify every amendment by a PE poses too great a cost, and the benefits do not justify the costs. (28, 69, 101, 165, L15)

Increase in discharge potential. We should require PE certification only for changes that *increase* a facility's potential to discharge oil. (95, 102, 167, L12)

Changes "affecting" discharge potential. We should require PE certification only for changes that affect a facility's potential to discharge oil. (33, 48, 67, 173, 175, L7)

“Modify” physical characteristics. We should require PE certification only for facility changes that modify the physical characteristics and engineering features described in the Plan. (115)

Substantive changes, three-year review. We should require Plan recertification only if the owner or operator makes substantive changes to the Plan or is engaged in the Plan three-year review. (75)

PE certification - technical amendments. Adopting the proposed requirement would result in less frequent Plan revision. (62) Decommissioning tanks, minor modifications to piping systems, and changes in operations or maintenance procedures at a facility should not require Plan recertification. (113, 165, L15) “Section 112.5(c) should be revised to allow some facility changes, including those changes requiring Plan amendments [see 112.5(a)] without the requirement to recertify the Plan.” (91, 133, 182)

PE Certification - Plan or amendment. We should clarify whether a PE must recertify the Plan or simply certify Plan amendments. (76)

Alternate certification suggested. We should revise §112.5(c) to allow either a geologist or hydrologist with a degree and five years experience; an engineer with a degree and five years experience; or a registered PE to certify Plan amendments. (70)

Response: *Support for proposal.* We appreciate commenter support. However, we have reduced the regulatory and information collection burden by permitting a five-year review interval, with the same technological conditions. We have also adopted the requirement proposed in 1997 that the owner or operator certify completion of the review.

PE certification. It is the responsibility of the owner or operator to document completion of review, but completion of review and Plan amendment are two different processes. PE certification is not necessary unless the Plan is amended.

PE certification - technical amendments. We believe that PE certification is necessary for any technical amendment that requires the application of good engineering practice. We believe that the value of such certification justifies the cost, in that good engineering practice is essential to help prevent discharges. Therefore, we have amended the rule to require PE certification for technical changes only. Non-technical changes not requiring the exercise of good engineering practice do not require PE certification. Such non-technical changes include but are not limited to items as: changes to the contact list; more stringent requirements for stormwater discharges to comply with NPDES rules; phone numbers; product changes if the new product is compatible with conditions in the existing tank and secondary containment; and, any other changes which do not materially affect the facility’s potential to discharge oil. If the owner or operator is not sure whether the change is technical or non-technical, he should have it certified.

PE Certification - Plan or amendment. The PE must only certify any amendments made when the owner or operator amends the Plan pursuant to §112.5(c), not the entire Plan.

Alternate certification suggested. We disagree that anyone other than a PE should certify a Plan or an amendment. See the discussion under section IV.D and under section V (relating to §112.3(d)) of today's preamble, and section VI.C of this document.

PE certification - standard for amendment. We disagree that we should require PE certification only for changes that would increase a facility's potential to discharge oil. We believe that an amendment is necessary when a facility change results in a decrease in the volume stored or a decrease in the potential for an oil spill because EPA needs this information to determine compliance with the rule. For example, the amount of secondary containment required depends on the storage capacity of a container.

Category IX: Civil Penalties - §112.6 (Rescinded)

Background: Section 112.6 of the original SPCC rule set out the civil penalties associated with violating various part 112 provisions. In 1991, we proposed a more extensive list of provisions, the violation of which would subject an owner or operator to these penalties.

Comments: Federal agencies are subject to civil penalties under the CWA. (42) Criminal penalties associated with negligent violations are unreasonable because one drop of oil is a harmful quantity. (62) The civil penalties stated in §112.6 are excessive – especially for small oil facilities. The penalty amounts might exceed a small operator’s net worth. (28, 101) The terms *substantial harm* and *sensitive (environments)* are vague, and owners or operators may face law suits as a consequence of various interpretations of these terms. (149) The amendment is unnecessary because current penalty provisions already encourage adequate containment and spill prevention measures. (192)

Response: We have not adopted the proposal that would expand the list of part 112 provisions and the civil penalties associated with violating those provisions because we rescinded §112.6 in 1996. We rescinded §112.6 because that penalty provision no longer accurately reflected the penalties provided for under section 311(b) of the Act, as amended by OPA. March 11, 1996, 61 FR 9646.

EPA disagrees that Federal agencies are subject to penalties or fines under the CWA because the Federal government is not a “person” under sections 311(a)(7) or 502 of the CWA. Only “persons” (including owners or operators and persons in charge) are subject to such penalties. Therefore, although Federal agencies must comply with requirements of a CWA section 311 rule in accordance with CWA section 313, they are not subject to civil or criminal penalties or fines. See U.S. Department of Energy v. Ohio, 503 U.S. 607, 618 (1992) (because the CWA does not define “person” to include the United States, the civil penalty provisions are not applicable.)

Category X: General substantive requirements - §112.7

X - A: Reorganization of the regulation - §112.7(a) and (a)(1) (See also section V - 14)

Background: In 1991, we proposed to separate §112.7 into five sections (§§112.7, 112.8, 112.9, 112.10, and 112.11), based on facility type to promote ease in using and understanding the regulation.

Proposed §112.7 provided general requirements for preparing SPCC Plans. The new sections addressed detailed Plan requirements for onshore facilities (excluding production facilities) (§112.8); onshore production facilities (§112.9); onshore oil drilling and workover facilities (§112.10); and offshore oil drilling, production, and workover facilities (§112.11). In reorganizing part 112 into sections, we intended no substantive change.

In 1995, Congress enacted Public Law 104-55, the Edible Oil Regulatory Reform Act (EORRA). That statute mandates that most Federal agencies differentiate between and establish separate classes for various types of oils. In response to EORRA, we have divided part 112 by subparts for the various classes of oil listed in that Act. Subpart A consists of an applicability section, definitions, and general requirements for all facilities. Subpart B is for petroleum oils and non-petroleum oils, except for animal fats and vegetable oils. Subpart C is for animal fats and oils and greases, and fish and marine mammal oils; and for oils of vegetable origin, including oils from seeds, nuts, fruits, and kernels. Subpart D is for response requirements.

Sequence of Plan. In 1991, in §112.7(a)(1), we repropose the requirement in the current §112.7 introductory paragraph that the Plan must follow the sequence outlined in §112.7, and include a discussion of how the facility conforms with the requirements listed in the rule. We modified the 1991 proposal in 1997 to allow alternate formats. See the preamble to today's rule and the 1997 Comment Response Document. In the final rule, the reference to sequence §112.7(a)(1) was relocated to the introductory paragraph of §112.7(a).

Current §112.7(a) - pre-1974 spills. Because the information was no longer relevant, in 1991, we proposed deletion of §112.7(a), which required a description of certain discharges to navigable waters or adjoining shorelines that occurred prior to the effective date of the rule in 1974.

Comments: *Current §112.7(a) - pre-1974 spills.* "This proposal to eliminate the inventory requirement is appropriate since records of pre-1973 discharges often do not exist, and even if these records are available, they provide no useful environmental protection benefit to current mining operations or to EPA and create a serious administrative and investigative burden." (25, 35, 114)

Management approval of Plan. We were unclear when we proposed in §112.7(a)(1) that “the Plan shall have the full approval of management at a level with authority to commit the necessary resources to fully implement the Plan.” We should clarify whether we require any documentation for this approval and whether there are any limitations on who we consider “management.” (115)

Sequence of Plan.

§112.7(a)(3). The sequence should be as outlined in §112.7(a)(3). It “would be most helpful to have the outline clearly stated by a paragraph immediately following Section 112.7(a)(1).” (121, L33)

Clarification needed. “The proposed rule is written in such a way that is unclear as to the proper format of the plan. ... We recommend that a guidance document containing examples of acceptable SPCC Plans be made available before or at the time of promulgation of the final rule.” (79)

No set sequence. “The Section 112.7(a)(1) requirement that all Plans follow a specific ‘sequence’ should be deleted. To require that all Plans to follow a predesignated sequence which may or may not be the most appropriate or useful for the facility personnel that must carry out the Plan is not in the best interest of protecting navigable waters. The Plan developers should be allowed the freedom to organize the Plan to suit the facility needs relative to SPCC requirements and to incorporate elements required by other regulations for the development of such emergency prevention and response plans. During an actual emergency, a consolidated Plan greatly enhances the effectiveness of the response.” (67, 95, 102, 175)

Recommendation instead. We should change the requirement to a recommendation, because a requirement provides no pollution prevention benefit. (95)

Support for reorganization. Support for our decision to separate §112.7 into five sections based on facility type. EPA recognized the differences in facility design and sought to provide the regulated community with greater certainty about its legal obligations. (27, 53, L4)

Opposition to reorganization. We would increase reporting requirements; replace an existing, satisfactory compliance program with one that asserts additional command and control authority; expand regulatory jurisdiction; and increase compliance costs to industry and society, while providing no incremental environmental protection benefit. (35) We are creating an unnecessary burden by restructuring the regulation. (16, 79)

Response: We have reorganized the rule text, placing §§112.8 through 112.11 into Subpart B. We have changed the section numbers of the provisions, but have not thereby imposed new requirements, nor expanded our jurisdiction or authority.

Current §112.7(a) - pre-1974 spills. In 1991, we proposed to delete §112.7(a), which required a description of certain discharges to navigable waters or adjoining shorelines which occurred prior to the effective date of the rule in 1974, because that information was no longer relevant. 56 FR 54620. We received several comments supporting the proposed deletion of this provision, and have deleted it.

Management approval of Plan. The owner or operator of the facility, or a person at a management level with sufficient authority to commit the necessary resources, must implement the Plan. That person may vary from facility to facility, therefore we cannot specify a certain title. Documentation of this authority is shown by signature on the Plan.

Sequence of Plan. In the 1997 proposal, we withdrew the 1991 proposal that would have required a Plan to follow the sequence outlined in §112.7. See the Response to Comments Document for the 1997 proposal for the comments and responses to that proposal.

X - B: Deviations - §112.7(a)(2)

Background: In 1991, we proposed to amend §112.7(a)(2) to permit the use of methods not expressly called for in proposed §112.7(c) and §§112.8 through 112.11, as long as these practices provided environmental protection equivalent to part 112 provisions. In the 1991 proposal, we said that we would retain our discretion to determine that an alternative method did not provide equivalent protection.

Comments: *Support for proposal.* This provision would encourage development of innovative spill prevention and control measures. (72, 164, 190, L29)

Opposition to proposal.

Electrical equipment. Requirements other than the secondary containment and integrity testing requirements -- may be impracticable for electrical equipment, including the proposed §112.8 drainage requirements and the requirement to provide detailed site plans, flow paths, and failure analyses. (125)

RA oversight.

“Apparent” equivalency. References the provision in proposed §112.8(b)(3) that “drainage systems from undiked areas ‘shall’ flow into ponds, lagoons, or catchment basins” as “one example of a requirement that does not lend itself to comparison with an ‘equivalent’ alternative.” Equivalency may not be apparent in some instances from the physical structure of the alternative measure. “...(I)n practice it will be impossible to prove equivalency to the satisfaction of EPA enforcement officials.” (125, 146, 170, 189, L27)

EPA evaluation. “An alternative is to require that Plans containing such a technical waiver be reviewed by US EPA in order to determine if such a method is applicable to the use intended.” Whether an alternate measure provides “equivalent alternate protection” depends on the facility and the location within the facility. (76)

Inspectors and equivalency. The “check-lists of requirements” that inspectors often carry do not include “equivalent environmental protection.” Because we did not provide guidance on what constitutes an *equivalent measure*, the inspector may be “unfamiliar with the unique operational characteristics of utility equipment.” (125)

Mathematical equivalency. We should clarify that §112.7(a)(2) does not require *mathematical equivalency* of every requirement, but rather, the “achievement of substantially the same level of overall protection from the risk of discharge at the facility as the specific requirement seeks to achieve.” It would be impossible to prove equivalency to the satisfaction of inspectors. (125, 170)

No RA oversight. Would delete provision allowing RA to overrule alternative measures selected under this section. (121)

Response: *Support for proposal.* We appreciate commenter support.

Applicability. We generally agree with the commenter that an owner or operator should have flexibility to substitute alternate measures providing equivalent environmental protection in place of express requirements. Therefore, we have expanded the proposal to allow deviations from the requirements in §112.7(g), (h)(2) and (3), or (i), as well as subparts B, and C, except for the listed secondary containment provisions in §112.7 and subparts B and C. The proposed rule already included possible deviations for any of the requirements listed in §§112.7(c), 112.8, 112.9, 112.10, and 112.11. We have expanded this possibility of deviation to include the new subparts we have added for various classes of oils. We take this step because we believe that the application of good engineering practice requires the flexibility to use alternative measures when such measures offer equivalent environmental protection. This provision may be especially important in differentiating between requirements for facilities storing, processing, or otherwise using various types of oil.

A deviation may be used whenever an owner or operator can explain his reasons for nonconformance, and provide equivalent environmental protection. Possible rationales for a deviation include when the owner or operator can show that the particular requirement is inappropriate for the facility because of good engineering practice considerations or other reasons, and that he can achieve equivalent environmental protection in an alternate manner. For example, a requirement that may be essential for a facility storing gasoline may be inappropriate for a facility storing asphalt; or, the owner or operator may be able to implement equivalent environmental protection through an alternate technology. An owner or operator may consider cost as one of the

factors in deciding whether to deviate from a particular requirement, but the alternate provided must achieve environmental protection equivalent to the required measure. The owner or operator must ensure that the design of any alternate device used as a deviation is adequate for the facility, and that the alternate device is adequately maintained. In all cases, the owner or operator must explain in the Plan his reason for nonconformance. We wish to be clear that we do not intend this deviation provision to be used as a means to avoid compliance with the rule or simply as an excuse for not meeting requirements the owner or operator believes are too costly. The alternate measure chosen must represent good engineering practice and must achieve environmental protection equivalent to the rule requirement. Technical deviations, like other substantive technical portions of the Plan requiring the application of engineering judgment, are subject to PE certification.

In the preamble to the 1991 proposal (at 56 FR 54614), we noted that "...aboveground storage tanks without secondary containment pose a particularly significant threat to the environment. The Phase One modifications would retain the current requirement for facility owners or operators who are unable to provide certain structures or equipment for oil spill prevention, including secondary containment, to prepare facility-specific oil spill contingency plans in lieu of the prevention systems." In keeping with this position, we have deleted the proposed deviation in §112.7(a)(2) for the secondary containment requirements in §§112.7(c) and (h)(1); and for proposed §§112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c); as well as for the new sections which are the counterparts of the proposed sections, i.e., §§112.12(c)(2), 112.12(c)(11), 112.13(c)(2), and 112.14(c), because a more appropriate deviation provision already exists in §112.7(d). Section 112.7(d) contains the measures which a facility owner or operator must undertake when the secondary containment required by §112.7(c) or (h)(1), or the secondary containment provisions in the rule found at §§112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), 112.12(c)(11), 112.13(c)(2), and 112.14(c), are not practicable. Those measures are expressly tailored to address the lack of secondary containment at a facility. They include requirements to: explain why secondary containment is not practicable; conduct periodic integrity testing of bulk storage containers; conduct periodic integrity and leak testing of valves and piping; provide in the Plan a contingency plan following the provisions of 40 CFR part 109; and, provide a written commitment of manpower, equipment, and materials to expeditiously control and remove any quantity of oil discharged that may be harmful. Therefore, when an owner or operator seeks to deviate from secondary containment requirements, §112.7(d) will be the applicable "deviation" provision, not §112.7(a)(2).

Deviation submission. We agree with the commenter that submission of a deviation to the Regional Administrator is not necessary and have deleted the proposed requirement. We take this step because we believe that the requirement for good engineering practice and current inspection and reporting procedures (for example, §112.4(a)), followed by the possibility of required amendments, are adequate to review Plans and to detect the flaws in them. Upon submission of required information, or upon on-site review of a Plan, if the RA decides that any portion of a Plan is

inadequate, he may require an amendment. See §112.4(d). If you disagree with his determination regarding an amendment, you may appeal. See §112.4(e).

RA oversight. Once an RA becomes aware of a facility's SPCC Plan as a result on an on-site inspection or the submission of required information, he is to follow the principles of good engineering practice and not overrule a deviation unless it is clear that such deviation fails to afford equivalent environmental protection. This does not mean that the deviation must achieve "mathematical equivalency," as one commenter pointed out. But it does mean equivalent protection of the environment. We encourage innovative techniques, but such techniques must also protect the environment. We also believe that in general PEs will seek to protect themselves from liability by only certifying measures that do provide equivalent environmental protection. But the RA must still retain the authority to require amendments for deviations, as he can with other parts of the Plan certified by a PE.

Not covered under the deviation provision. Deviations under §112.7(a)(2) are not allowed for the general and specific secondary containment provisions listed above because §112.7(d) contains the necessary requirements when you find that secondary containment is not practicable. We have amended both this paragraph and §112.7(d) to clarify this. Instead, the contingency planning and other requirements in §112.7(d) apply. Deviations are also not available for the general recordkeeping and training provisions in §112.7, as these requirements are meant to apply to all facilities, or for the provisions of §112.7(f) and (j). We already provide flexibility in the manner of record keeping by allowing the use of ordinary and customary business records. Training and a discussion of compliance with more stringent State rules are essential for all facilities. Therefore, we do not allow deviations for these measures.

X - C: Plan information - §112.7(a) and (b)

Background: In 1991, in §112.7(a)(1), we reposed the requirement in the current §112.7 introductory paragraph that the Plan must follow the sequence outlined in §112.7, and include a discussion of how the facility conforms with the requirements listed in the rule.

In proposed §112.7(a)(3)(i)-(ix), we clarified which facility characteristics which the owner or operator must describe in the Plan, including unit-by-unit storage capacity; type and quantity of oil stored; estimates of quantity of oils potentially discharged; possible spill pathways; spill prevention measures; spill control measures; spill countermeasures; provisions for disposal of recovered materials; and a contact list with appropriate phone numbers. We also proposed a requirement for a facility diagram on which the location and contents of all tanks would be marked.

Under proposed §112.7(a)(4), an owner or operator would have to provide documentation in the Plan that would enable a person reporting a spill to provide spill-specific information, including the exact address and phone number of the facility; the spill date and time; the type of material spilled; estimates of the total quantity spilled;

estimates of the quantity spilled into navigable water; the spill's source; a description of the affected medium; the spill's cause; any damages or injuries caused by the spill; actions being used to stop, remove, and mitigate the effects of the discharge; whether an evacuation may be needed; and the names of individuals and/or organizations who had also been contacted.

Current §112.7(b) requires that, where experience indicates a reasonable potential for equipment failure (e.g., tank overflow, rupture, or leakage), the owner or operator must include in the Plan a prediction of the direction, rate of flow, and total quantity of oil that could be discharged from the facility as a result of each major type of failure. In §112.7(b), we proposed to clarify that the requirements for discharge prediction were not contingent on the past spill experience of a facility.

X-C-1 Facility physical description and diagram - §112.7(a)(3)

Background: In 1991, in §112.7(a)(3), we proposed to require that a Plan include a facility diagram on which are marked the location and contents of all tanks. We also proposed to require that an owner or operator address in the Plan the essential facility characteristics listed in §112.7(a)(3)(i)-(ix).

Comments: *Support for proposal.* “GM supports the proposed SPCC plan requirements detailing physical attribute of the facility, such as capacity, types of oil, pathways, etc.” (76, 90)

Opposition to proposal. “Overall, for large facilities such as refineries, the amount of detail required in 112.7(a)(3) is unreasonable, very resource intensive to compile and too voluminous for Agency staff to assimilate or evaluate. API believes the level of detail required will add little value to the Plan for large facilities such as refineries.” (67)
Contents of tank. “However, including the contents of the tanks on the diagram is not practical. First, many of the tanks are used for different products depending on seasonal fluctuations and other market demands; and by other proposed changes the plan would require amendment for each such change. Secondly, if there are more than just a handful of tanks, it is difficult for a new visitor to a facility to identify which tank contains products which are potentially explosive, reactive, corrosive, or otherwise dangerous to emergency spill response.” (76, 92)

Containers not storing oil. Asks whether “exempt ASTs which do not contain oil” should be marked on a facility diagram. “It would seem consistent with the reasoning for showing tanks exempt due to their UST status (i.e., emergency response crews would be able to identify oil containing tanks from those with other materials.)” (62)

Risk. Suggests “Alternative wording, such as ‘...indicate the type of product (crude oil, gasoline, acid, etc.) or other information as necessary to expediently evaluate the relative hazards presented’ would be more appropriate. In addition,

requiring recommending methods to readily identify such tanks by on-tank displays would be prudent as well.” (76)

Facility diagram - De minimis containers. “112.7(a)(3) Requirement for plan to describe location and contents of all tanks will be unwieldy if even very small containers must be included. Request that *de minimis* level exemptions be established.” (62, 66, 125, 179, 184)

660 gallons. “API believes tanks with less than capacity of 660 gallons should not be included on the facility diagram. These tanks are excluded from current SPCC regulations and mandating inclusion of such tanks would make the facility diagram less useful due to increased clutter. The cost of preparing the diagram would also increase substantially. Furthermore such tanks are often portable, making inclusion on a facility diagram impractical.” (67)

Facility diagram, exempt materials. Asks whether exempt USTs which do not contain oil should be marked on facility diagrams. “It would seem consistent with the reasoning for showing tanks exempt due to their UST status (i.e., emergency response crews would be able to identify oil containing tanks from those with other materials.)” (62) “Subjecting otherwise exempt facilities to the requirements for ... facility diagrams (112.7(a)(3)) is unreasonable considering the negligible risk posed by facilities ‘not reasonably expected to discharge oil’.” (167)

Facility diagram - Transfer stations, connecting pipes, and USTs. We should require an owner or operator to include in the Plan a diagram that shows transfer stations and connecting pipes. (111)

General description of characteristics.

Approved substances. “...BP proposes that facility storage tank diagrams be required to show the location of tanks and products approved to be stored in that type of storage tank (ie. cone roof, internal or external floating roof, heated, etc.). A list of possible substances (gasolines, diesel fuels, residual oils, crude oils, etc.) approved to be stored in each tank or type of tanks would be indicated on the facility diagram or elsewhere in the SPCC Plan. The log book and facility status board would then provide information on the current contents of each tank.” (96)

Facility based information. We should require that the owner or operator address §112.7(a)(3) information “on a facility basis.” “This addition would clarify the detail needed for the Plan and make it consistent with the type of information required in the Section 112.1(e), notification requirements. Since storage capacity and type and quantity stored in each tank is not required in the notification requirements, it should not be required in this Plan.” (67)

Numbered list. Would revise §112.7(a)(3) to read: “The complete plan must describe the facility’s physical plant and include a facility diagram, which must indicate the location of all tanks which shall be numbered, and it must be accompanied by a separate list of all the numbered tanks. Those tanks in oil service must have their contents listed after the tank number on the tank list. A facility shall maintain an up-to-date list of tank contents as part of the SPCC plan and shall furnish it to EPA upon request. If tanks have been removed or added to a facility, the facility must submit a new tank diagram and a list of numbered tanks which states the contents of those in oil service.” (143)

Potential to contaminate navigable water. “EPA should provide additional clarification that the required facility diagram is intended to be of a level of detail to support the evaluation of the potential for an oil spill to reach navigable water and that a block diagram of only those facility components directly related to this risk (e.g., non-process equipment) is the minimum performance standard.” (L12)

Physical description of facility. “Descriptions of the physical plant at a facility are provided under many existing state regulatory schemes. Once again, the Agency is urged to develop a better approach to working with State regulatory authorities instead of redoubling the burden on the regulated community.” (42)

Response requirements. We should separate response plan requirements from spill prevention plan requirements, removing all response plan requirements from §§112.7(a)(3)(viii) and (ix), (a)(4), and (a)(5) and grouping them in another section containing only response plan requirements. (121)

Small facilities.

Small production facilities. “OOGA believes that the facility diagram requirement will be extremely burdensome to the small entity with no real environmental benefit, and particularly on the crude oil production facility owner who would be obligated to construct one for each of its facilities. Once again, for the reasons set forth above, OOGA requests that USEPA exempt these small facilities from the exception.” (28, 31, 58, 70, 86) Such a requirement would add two hours to the facility review process. (70) This requirement would be burdensome and of limited value because many facilities have only one tank. We should allow more time for an owner or operator to comply or require him to create a facility diagram by the end of the three-year review process. (101)

Specific Plan requirements. We should require the owner or operator to address the requirements, where applicable, listed in §§112.8, 112.9, 112.10, and 112.11 in the Plan. (121)

Response: *Support for proposal.* We appreciate the commenter support.

General description of characteristics. The following characteristics must be described on a per container basis: the storage capacity of the container, type of oil in each container, and secondary containment for each container. The other characteristics may be described on a facility basis. Based on site inspections and professional judgment, we disagree that these requirements are too resource intensive. The major new requirement in §112.7(a)(3) is the facility diagram. Based on site inspections and professional judgment, we estimate unit costs for compliance with this section to be \$33 for a small facility, \$39 for a medium facility, and \$5 for a large facility. Large facilities are assumed to already have a diagram that may be attached to the SPCC Plan. The other items mentioned in §112.7(a)(3) - storage capacity of each container, prevention measures, discharge controls, countermeasures, disposal methods, and the contact list - are already required under the current rule or required by good engineering practice. As described in the Information Collection Request for this rule, the cost of Plan preparation includes these items, e.g., field investigations to understand the facility design and to predict flow paths and potential harm, regulatory review, and spill prevention and control practices.

Providing information on a container-specific basis helps the facility to prioritize inspections and maintenance of containers based on characteristics such as age, capacity, or location. It also helps inspectors to prioritize inspections of higher-risk containers at a facility. Container-specific information helps an inspector verify the capacity calculation to determine whether a Plan is needed; and, helps to formulate contingency planning if such planning is necessary.

Facility diagram. The facility diagram is important because it is used for effective prevention, planning, management (for example, inspections), and response considerations and therefore we believe that it must be part of the Plan. The diagram will help the facility and emergency response personnel to plan for emergencies. For example, the identification of the type of oil in each container may help such personnel determine the risks when conducting a response action. Some oils present a higher risk of fire and explosion than other than less flammable oils.

Inspectors and personnel new to the facility need to know the location of all containers subject to the rule. The facility diagram may also help first responders to determine the pathway of the flow of discharged oil. If responders know possible pathways, they may be able to take measures to control the flow of oil. Such control may avert damage to sensitive environmental areas; may protect drinking water sources; and may help responders to prevent discharges to other conduits leading to a treatment facility or navigable waters. Diagrams may assist Federal, State, or facility personnel to avoid certain hazards and to respond differently to others.

The facility diagram is necessary for all facilities, large or small, because the rationale is the same for both. While some States may require a diagram, others do not. SPCC is a Federal program specifying minimum requirements, which the States may supplement with their own more stringent requirements. We note that State plans may be used as

SPCC Plans if they meet all Federal requirements, thus avoiding any duplication of effort if the State facility diagram meets the requirements of the Federal one.

Facility diagram - container contents. The facility diagram must include all fixed (i.e., not mobile or portable) containers storing 55 gallons or more of oil and must include information marking the contents of those containers. If you store mobile containers in a certain area, you must mark that area on the diagram. You may mark the contents of each container either on the diagram of the facility, or on a separate sheet or log if those contents change on a frequent basis. Marking containers makes for more effective prevention, planning, management, and response. We disagree that a list of products approved for storage in the container is sufficient for emergency response. While a document outlining what materials might be stored in a container is useful, it does not say what is actually in it at a particular time. For example, a responder may take one type of emergency measure for one type of oil, and another measure for another type. As noted above, oils differ in their risk of fire and explosion. Gasoline is highly flammable and volatile. It presents the risk of fire and inhalation of vapors when discharged. On the other hand, motor oil is not highly flammable, and there is no inhalation of vapors hazard associated with its discharge.

In an emergency, the responder may not have container content information unless it is clearly marked on a diagram, log, or sheet. For emergency response purposes, we also encourage, but do not require you to mark on the facility diagram containers that store CWA hazardous substances and to label the contents of those containers. When the contents of an oil container change, this may or may not be a material change. See the discussion on §112.5(a).

Facility diagram - De minimis containers. We have established a *de minimis* container size of less than 55 gallons. You do not have to include containers less than 55 gallons on the facility diagram.

Facility diagram - Transfer stations, connecting pipes, and USTs. We agree that all facility transfer stations and connecting pipes that handle oil must be included in the diagram, and have amended the rule to that effect. This inclusion will help facilitate response by informing responders of the location of this equipment. The location of all containers and connecting pipes that store oil (other than *de minimis* containers) must be marked, including USTs and other containers not subject to SPCC rules which are present at SPCC facilities. Again, this is necessary to facilitate response by informing responders of the location of these containers.

Physical description of facility. We appreciate the commenter's support. In the final rule, we have changed the requirement for a description of the "physical plant" of the facility to a description of the "physical layout" of the facility. If the owner or operator has provided that information in a State plan, he may use the same information in his Federal SPCC Plan if the State requirement is cross-referenced to the Federal requirement.

Response requirements. We generally agree that response plan requirements should be separate from spill prevention plan requirements. However, the information required in §112.7(a) facilitates response to an emergency and is necessary for all facilities. Because a facility with a response plan already documents the required information, we have therefore have exempted any such facility from documenting certain information required for SPCC facilities in §112.7(a). See, for example, revised §112.7(a)(3), (4), and (5). We disagree that there is no need for §112.7(d). The Minerals Management Service (MMS) is not responsible for all offshore oil production facilities. Offshore facilities in the inland area fall under EPA jurisdiction. (See EO 12777.)

Specific Plan requirements. We agree that an owner or operator should address specific requirements applicable to a facility. Section 112.7(a)(1) requires a facility owner or operator to discuss how a facility conforms with part 112 requirements. Furthermore, the introductions to §§112.8, 112.9, 112.10, 112.11, 112.12, 112.13, 112.14, and 112.15 reference the obligation to address both general and specific requirements for the facility.

X-C-2 Unit-by-unit storage capacity - §112.7(a)(3)(i)

Background: In 1991, in §112.7(a)(3)(i), we proposed to require that an owner or operator address unit-by-unit storage capacity in the Plan.

Comments: *Minimum size.* We should specify a minimum size for units that owners or operators must include in the Plan. (62, 66, 79, 125, 164, 170, 184)

Small sizes.

Opposition to proposal. Requiring owners or operators to itemize small units would be unnecessarily costly and burdensome with little to no additional environmental benefit. (62, 66, 125, 164, 170)

Alternative sizes suggested.

660 gallons or less. Tanks containing greater than 660 gallons. (92, 125, 164)

10,000 gallons - electrical equipment. Electrical equipment containing greater than 10,000 gallons of oil or dielectric fluid. (125, 170, 184) If small pieces of equipment at electrical substations “catastrophically” fail, they do not fail synergistically and create other failures. We should not focus on controlling spills from small pieces of equipment that are only a few gallons and are quickly cleaned up. (164)

Mobile containers. According to the proposed requirement, an owner or operator would have to revise the Plan every time a drum of oil was received or a piece of oil containing manufacturing equipment was moved within the facility. (79)

“Unit.” We did not define the term *unit*, and we should clarify whether we meant *tank-by-tank* storage capacity. (28, 31, 101, 165, L15)

Response: *Minimum size.* Under §112.1(d)(5) of the final rule, part 112 does not apply to aboveground or completely buried containers with an oil storage capacity of less than 55 gallons. Therefore, the owner or operator need not include in the Plan containers smaller than 55 gallons. If the containers move frequently, the owner or operator may mark the location of those containers on a separate sheet or log. Movement of containers may or may not be a material change in the Plan requiring amendment, depending on whether the move increases or decreases the risk of a discharge.

“Unit.” For clarity, we have changed the term *unit-by-unit storage capacity* to *type of oil in each container and its storage capacity*.

X-C-3 Type and quantity of oil stored - proposed §112.7(a)(3)(ii)

Background: In 1991, in §112.7(a)(3)(ii), we proposed to require an owner or operator to address in the Plan the type and quantity of oil stored at the facility.

Comment: “Because the way a tank is used changes often and the adequacy of response to an accidental discharge does not hinge on the type of oil stored, Conoco cannot support this requirement.” (75)

Response: We have eliminated proposed §112.7(a)(3)(ii) in the final rule because it repeats information requested in revised §112.7(a)(3)(i). We disagree with the assertion that the responder’s knowledge of the type of oil stored does not affect the adequacy of response. Responders use different emergency measures for different types of oil.

X-C-4 Estimates of quantities of oil potentially discharged - proposed §112.7(a)(3)(iii)

Background: In 1991, in §112.7(a)(3)(iii), we proposed a requirement that an owner or operator address estimates of the quantity of oils that could be discharged.

Comments: See section XI-C–12 of this document for the comments on this paragraph.

Response: We have eliminated proposed §112.7(a)(3)(iii) in the final rule because it repeats information sought in §112.7(b) regarding “a prediction of the direction, rate of flow, and total quantity of oil that could be discharged.” We address substantive comments under the discussion of that paragraph.

X-C-5 Spill pathways - proposed §112.7(a)(3)(iv)

Background: In 1991, in §112.7(a)(3)(iv), we proposed to require an owner or operator to address possible spill pathways in the Plan.

Comments: See section XI-C-12 of this document for comments on this issue.

Response: We have eliminated proposed §112.7(a)(3)(iv) in the final rule because it repeats information sought in final §112.7(b), which asks for “a prediction of the direction, rate of flow, and total quantity of oil that could be discharged” as a result of each type of major equipment failure. We address the substantive comments under the discussion of that provision.

X-C-6 Spill prevention measures - §112.7(a)(3)(ii)

Background: In 1991, in §112.7(a)(3)(v), redesignated in the final rule as §112.7(a)(3)(ii), we proposed to require the owner or operator to address in the Plan spill prevention measures, including procedures for routine handling of products.

Comment: We should replace §112.7(a)(3)(v) with the words *secondary containment*. (121)

Response: We adopted the term *discharge prevention measures* in the final rule rather than *secondary containment*, because the term encompasses both secondary containment and other discharge prevention measures.

X-C-7 Spill controls and secondary containment - §112.7(a)(3)(iii)

Background: In 1991, in §112.7(a)(3)(vi), redesignated in the final rule as §112.7(a)(3)(iii), we proposed to require that the owner or operator address in the Plan spill controls such as secondary containment around tanks and other structures, equipment, and procedures for the control of a discharge.

Comments: *Drainage controls.* We should replace this provision with the requirement that owners or operators address “other drainage control features, and the equipment (pipes, pumps, meters, etc.) which they protect.” (121)

NASA standards. The National Aeronautics and Space Administration’s (NASA’s) Scientific and Technical Information (STI) Program standards should meet this spill control requirement. (140)

Underground piping, completely buried tanks. We should clarify that underground piping does not need secondary containment. (57)

Response: *Drainage controls.* We agree with the commenter. In the final rule, we have revised the requirement to refer to *discharge or drainage controls* to clarify that

drainage systems or diversionary ponds could serve as alternative means of secondary containment.

NASA standards. An owner or operator may follow STI standards for spill control if they meet part 112 requirements, but must discuss in the Plan how those standards meet these requirements.

Underground piping, completely buried tanks. Underground piping is subject to the secondary containment requirements in §112.7(c). Whether you install secondary containment around such piping involves issues of practicability and the reasonable possibility of a discharge as described in §112.1(b). The same rationale applies to completely buried storage tanks.

X-C-8 Spill countermeasures - §112.7(a)(3)(iv)

Background: In 1991, in §112.7(a)(3)(vii) (redesignated as §112.7(a)(3)(iv) in the final rule), we proposed to require the owner or operator to address in the Plan spill countermeasures for spill discovery, response, and clean-up (facility's capability and those that might be required of a contractor).

Comments: *Contingency planning.* "For clarity, EPA should consider trying to consolidate the contingency planning requirements located in these paragraphs. For example, 112.7(b) required a prediction of total quantity of oil that could be released and prediction of the direction of flow. This same information is already required under 112.7(a)(3)(iii) and (iv). In 112.7(a)(3)(vii) spill countermeasures for spill discovery, response, and cleanup are required. It appears that this same type of information is again required under 112.7(d)(1) where a contingency plan including a description of response plans, personnel needs, and methods of mechanical containment are required." (16)

Editorial suggestion. We should change this provision to require the owner or operator to address "prevention, control, or countermeasure features, other than secondary containment and drainage control, and the equipment which they protect" in the Plan. (121)

Response: *Contingency planning.* We disagree that these provisions are duplicative. Each section requires discrete information. Section 112.7(a)(3)(iv) requires information concerning a facility's and a contractor's capabilities for discharge discovery, response, and cleanup. We also note that §112.7(b) requires information concerning the potential consequences of equipment failure. Section 112.7(d)(1) requires a contingency plan following the provisions of part 109, which includes coordination requirements with governmental oil spill response organizations.

Editorial suggestion. We disagree with the suggestion. We believe the language we proposed, as revised, better captures the information we are seeking. Our revised language refers to discovery, response, and cleanup, which are features that are absent

from the commenter's suggestion, and for which a discussion in the Plan is necessary in order to be prepared for any discharges.

X-C-9 Disposal of recovered materials - §112.7(a)(3)(iv)

Background: In 1991, in §112.7(a)(3)(viii) (redesignated as §112.7(a)(3)(v) in the final rule), we proposed to require the owner or operator to address the disposal of recovered materials in the Plan.

Comments: *Support for proposal.* "Conoco supports the requirement that the plan address applicable state laws, federal laws, and disposal options. However, it would be neither feasible nor useful to discuss particular alternatives." (75)

Opposition to proposal.

Certification. "Detailed provisions for disposal of recovered materials is unreasonable for manufacturing facilities which may have small quantities of many types of oil and petroleum materials. A certification that disposal will be in compliance with all federal and state regulations should be sufficient for 'small size' facilities." (62)

Regulatory duplication. "APC believes that the disposal of material recovered are regulated by State law and/or RCRA and a discussion of this subject in the Plan is inappropriate." (58, 66, 125, 164, 170, L12)

Specific options. "The proposed regulations seem to require that commitments be made for specific disposal options for wastes which have not been generated. The federal and state solid waste disposal options and requirements are complex and changing. We suggest that disposal commitments in the SPCC Plan be limited to a statement which commits to disposal of wastes in accordance with applicable regulatory requirements." (70, 75, 92, 125, L12)

Unnecessary. "SPCC Plans prepared under the current regulation do not require this information. Furthermore, such practices may already be included in other Plans such as Best Management Practices Plans or RCRA Contingency Plans." (79) The issue of waste disposal does not belong in a document designed to address preventing oil contamination to navigable waters. (164) We should clarify why we have included this new provision. The disposal of oil spill clean-up waste does not impede spill containment or clean-up activities. (L12)

Authority. We do not have the authority under the CWA to request this information. (28, 58)

Bioremediation. "On-site bioremediation would be a much more economical and practical means of cleaning up an oil spill to achieve an equivalent environmental benefit." (101, 113)

Costs. The requirement to address disposal of recovered materials in the Plan may have major cost implications. (31, 165, L15)

Recycling. “...(W)e also believe the SPCC regulation should encourage recycling of spilled oil to the extent possible.” (61)

Response: *Support for proposal.* We appreciate the commenter support.

Applicability, necessity for proposal. This provision applies to all facilities, including mobile facilities, because proper disposal of recovered materials helps prevent a discharge as described in §112.1(b) by ensuring that the materials are managed in an environmentally sound manner. Proper disposal also assists response efforts. If a facility lacks adequate resources to dispose of recovered oil and oil-contaminated material during a response, it limits how much and how quickly oil and oil-contaminated material is recovered, thereby increasing the risk and damage to the environment. A commitment to dispose of materials in accordance with applicable laws is by itself insufficient, because we need evidence of actual methods employed.

Onshore or offshore mobile drilling and workover rigs. We disagree that either onshore or offshore mobile drilling and workover rigs should be exempted from this requirement because the information necessary to this requirement is not always site specific, and may be included in a general plan for a mobile facility.

Authority. Under section 311(j)(1)(C) of the CWA, we have authority to establish procedures, methods, equipment, and other requirements to prevent and contain oil discharges. Collecting information on disposal of recovered materials is a procedure or method to help prevent or contain discharges.

Bioremediation. We disagree that this paragraph would preclude bioremediation efforts, as some commenters suggested. Bioremediation may be a method of proper disposal.

Cost. Because it does nothing more than require that you explain the method of disposal of recovered materials, we also disagree that this provision is too costly. Also, we assume that good engineering practice will in many cases include a discussion of such disposal already. By describing those methods in the Plan, you help ensure that the facility has done the appropriate planning to be able to dispose of recovered materials, should a discharge occur.

Editorial suggestion. We disagree that we should replace the proposed language with language requiring that the owner or operator dispose of materials in accordance with proper State and Federal regulations. Our proposed language captures both State and Federal regulations and is more succinct.

Recycling. We support the recycling of spilled oil to the extent possible, rather than its disposal. For purposes of this rule, disposal of recovered materials includes recycling of those materials.

Regulatory duplication. The paragraph merely requires that you discuss the methods employed to dispose of recovered materials; it does not require that materials recovered be “disposed” of in any particular manner nor is it an independent requirement to properly dispose of materials. Thus, there is no infringement on or duplication of any other State or Federal program or regulatory authority.

X-C-10 Contact list - §112.7(a)(3)(vi)

Background: In 1991, in §112.7(a)(3)(ix), redesignated in the final rule as §112.7(a)(3)(vi), we proposed to require that an owner or operator include in the Plan a contact list and phone numbers for the facility response coordinator, the National Response Center (NRC), clean-up contractors, fire departments, the LEPC, the SERC, and downstream water suppliers.

Comments: *Support for proposal.* “The inclusion of an ‘Emergency Contact List’ is appropriate. Kerr-McGee E&P/USO (United States Onshore) SPCC Plans include such a proposed Emergency Contact List.” (27, 90, 114, L11)

Agreement for response. We should change our proposal to require that the owner or operator identify the following: “Each cleanup contractor that has agreed in writing...to respond to a spill at the facility, the period of time that the cleanup contractor’s commitment is valid, an enumeration of the types of spills to which each cleanup contractor is licensed to remediate, and the listing of the license number(s) and license expiration date(s) for each cleanup contractor.” Otherwise, many owners or operators will not check whether the clean-up contractor list is current. (47)

Applicability.

Mobile facilities. Because they move from site-to-site, we should exempt an owner or operator of an onshore and offshore mobile drilling and workover rigs from our §112.7(a)(3)(vii)-(ix) requirements to list spill countermeasures, contact lists, and material disposal methods in the Plan. (128)

Authority. We do not have the authority under the CWA to require the owner or operator to list State emergency response phone numbers in this provision of the Plan. Such a requirement is within the State’s exclusive authority. (58)

Downstream water suppliers.

Affected by a discharge. “This requirement should be modified to make clear that only downstream water suppliers who might reasonably be affected by a discharge must be notified.” (28, 31, 92, 101, 125, 165, 170, 189, L02, L15)

Alternatives to notice. “In addition, the facility operator should be given the option of notifying the local entities such as the local emergency planning committee and leave the notification of individual water suppliers to that body.” (62, 66, 92, 125, 170, 189)

Basis for estimates. We should base the applicability of §112.7(a)(3)(ix) on estimates of quantities of oils potentially discharged. (28)

Case-by-case determination. An owner or operator should assess each spill, and determine case-by-case which downstream water suppliers to notify. (66)

Central registry of suppliers. “Where does an operator obtain a list of water suppliers? Water suppliers should be located in a central registry to help operators discover who they are.” (28, 31, 165, L15)

Distance. “There must be a downstream distance limit placed on this based on estimates of quantities of oil potentially discharged. This should not include private wells.” (28, 31, 92, 101)

“Endless” list. A list of downstream water suppliers could be endless. The LEPC or the U.S. Coast Guard should determine which downstream water suppliers to alert. (164)

Suppliers of record. Only “water suppliers of record” should be notified. (31, 165, L15)

Unnecessary requirement. This requirement is unnecessary and costly for Appalachian producers. (101) Local and State emergency response authorities already collect all information regarding downstream water suppliers pursuant to the Federal Emergency Planning and Community Right-to-Know Act, and regulations promulgated thereto. This paragraph should be deleted and removed to a response plan section because the information called for requires response information. (62, 189)

Whom should be notified.

Agencies notified of accidental discharges. In keeping with the SPCC Program’s focus on accidental discharge prevention and response, we should require that the contact list include only those State and Federal agencies that must be notified of an accidental oil discharge. (75)

LEPC, SERC, USCG. We should require owners or operators to include only the LEPC, SERC, and the U.S. Coast Guard in the contact list. (164)

Response: *Support for proposal.* We appreciate commenter support.

Agreement for response. In response to a comment, we have amended the rule to require that the cleanup contractor listed must be the one with whom the facility has an agreement for response that ensures the availability of the necessary personnel and equipment within appropriate response times. An agreement to respond may include a contract or some less formal relationship with a cleanup contractor. No formal written agreement to respond is required by the SPCC rule, but if you do have one, you must discuss it in the Plan.

Applicability, mobile facilities. We disagree that either onshore or offshore mobile drilling and workover rigs should be exempted from this requirement because the information necessary to this requirement is not always site specific, and may be included in a general plan for a mobile facility.

Authority. We have ample authority to ask for information concerning emergency contacts under the CWA because it is relevant to the statute's prevention, preparedness, and response purposes. CWA section 311(m)(2). Furthermore, it is an appropriate question for all facilities, including mobile facilities, because it is necessary to prepare for discharges and to aid in prompt cleanup when they occur. Having a Plan which contains a contact list of response organizations is a procedure and method to contain a discharge of oil as specified in CWA section 311(j)(1)(C).

Downstream water suppliers. We have deleted the reference to "downstream water suppliers" (i.e., intakes for drinking and other waters) because facilities may have no way to identify such suppliers. We agree with commenters that identifying such suppliers is more a function of State and local emergency response agencies. We note, however, that facilities that must prepare response plans under §112.20 must discuss in those plans the vulnerability of water intakes (drinking, cooling, or other).

Response section. We disagree that the information should be placed in a response section, because most SPCC facilities are not required to have response plans, and the information is necessary to prepare for response to an emergency.

Whom should be notified. We have eliminated references to specific State and local agencies in the event of discharges in favor of a reference to "all appropriate State and local agencies." "Appropriate" means those State and local agencies that must be contacted due to Federal or State requirements, or pursuant to good engineering practice. You may not always be required to notify fire departments, local emergency planning committees (LEPCs), and State emergency response commissions (SERCs), nor as an engineering practice do they always need to receive direct notice from the facility in the event of a discharge as described in §112.1(b). At times they might, but they might also receive notice from other sources, such as the National Response Center. Other State and local agencies might also need notice from you. We have added the word "Federal" to the list of all appropriate contact agencies because there are times when you must notify EPA of certain discharges. See §112.4(a). There might

also be requirements under other Federal statutes, other than the CWA, for notice in such emergencies.

X-C-11 Spill reporting requirements - §112.7(a)(4)

Background: In 1991, in §112.7(a)(4), we proposed to require that the owner or operator include in the Plan documentation enabling a person reporting a spill to provide essential information.

Comments: *Opposition to proposal, necessity for it.* We should not expand the Plan content requirements if we seek to simplify the Plan. Provisions such as the spill reporting requirements in (a)(4) “frustrate any attempts to clarify the regulatory framework.” (42) We should: “Delete and remove to response plan.” (117, 121)

Documentation. Rather than requiring an owner or operator to provide documentation in the Plan, we should require that “the information addressed in the Plan shall enable a person” to report a spill in accordance with the rest of the paragraph’s requirements. By requiring documentation, we would decrease the Plan’s usefulness as an emergency response tool. (75)

Delayed reporting. We should not require documentation that may be unavailable to the person initially reporting the spill, or highly speculative. If we require this information from the spill reporter, notification from the facility may be less prompt. (16)

Future event. “It is not possible to provide ‘documentation in the Plan’ which will enable a person reporting a spill to provide information on the spill date, time, type of materials spilled, estimation of the total quantity spilled, etc., if the spill has not happened. Suggest that this section be qualified to indicate that a form for collecting such information be included either in the plan, or for ‘small size facilities’ in the HAZWOPER reporting matrix.” (62)

Inapplicable information. Some of the information we would require may not apply to a wide variety of facilities. (167, 175)

Unavailable information. “Not all of the information listed for the purposes of reporting a release will be ‘available’ to the person reporting the discharge or ‘applicable’ to the discharge incident or to the facility at which the release took place.” (67, 85, 117, 167, 175)

Editorial suggestion. We should replace the word *spill* with the word *discharge* or *release*. A spill does not necessarily result in a discharge or a release to navigable waters, and we should not require reporting when a spill or leak has been fully contained. (39)

Facility address and phone number. Many facilities have no address or telephone. We should require that an owner or operator provide the facility location rather than the address and phone number. (28, 67, 70, 128, 133, 167, L12)

Response plan. “This is part of response. Delete and remove to response plan.” (121)

State requirements. The spill reporting provision duplicates State regulations. (167)

Response: *Opposition to proposal, necessity for it.* We disagree that we should eliminate a requirement to provide information and procedures concerning the cause of a discharge or its effects. Such information and procedures in the Plan is necessary to enable a person reporting a discharge to accurately describe information concerning that occurrence to the proper persons in an emergency.

Documentation. We agree with commenters that the word “documentation” is inappropriate because it refers to a past event. Accordingly, as suggested by commenters, we have revised the rule to provide for “information and procedures” that would assist the reporting of discharges as described in §112.1(b). “Information” refers to the facts which you must report, and “procedures” refers to the method of reporting those facts. Such procedures must address whom the person relating the information should call, in what order the caller should call potential responders and others, and any other instructions necessary to facilitate notification of a discharge as described in §112.1(b). If properly noted, the information and procedures in the Plan should enable a person reporting a discharge to accurately describe information concerning that occurrence to the proper persons in an emergency. Any information or procedure not applicable will not have to be used. Available information on a discharge must be reported. Applicable procedures must be followed. And of course, any information that is not available cannot be reported.

Editorial suggestion. In the final rule we have replaced *spill* with the term “discharge of oil as described in §112.1(b).” If a discharge is fully contained and never reaches navigable water or adjoining shorelines, it need not be reported.

Facility address and phone number. In the final rule we have changed *address* to *address or location* because some facilities do not have an exact address. Location may mean the longitude and latitude of the facility or some other identifiable means of pinpointing the facility. The phone number must be accurate, if the facility has a phone. Of course, if the facility has no phone, that fact must be noted.

State requirements. While it is possible that this information may be duplicative of State requirements, the duplication is eliminated to the extent that you use your State SPCC Plan for Federal SPCC purposes. Where there is no State requirement, there is no duplication.

Response plan exemption. We disagree that this paragraph should be placed in a response section, because most SPCC facilities are not required to have response

plans, and the information is necessary to prepare for response to an emergency. If your facility has prepared and submitted a response plan to us under §112.20, there is no need to document this information in your SPCC Plan, because it is already contained in the response plan. See §112.20(h)(1)(i)-(viii). Therefore, we have amended the rule to exempt those facilities with response plans from the requirements of this paragraph.

X-C-12 Fault analysis - §112.7(b)

Background: Proposed §112.7(b) would require an analysis of the major types of failures possible in a facility, including a prediction of the direction, rate of flow, and total quantity of oil that could be discharged as a result of such failures.

Comments: *Applicability.*

Large facilities. “Such an effort with its associated risk assessment is very complex and is not needed for most regulated facilities. EPA should specify that such an analysis is only required for very large facilities with potential for major harm to nearby receptors. Small to medium-sized facilities should limit such analyses to the identification of receptors located in spill pathways.” (51, 62, 107, 165, 192, L15, L17)

Mobile facilities. We should exempt mobile facilities from the requirement that owners or operators include in the Plan site-specific information on flow direction, rate of flow, and quantity of oil discharged. Site-specific information changes when the equipment moves. (128)

Present rule adequate. “API believes that the current section 112.7(b) language is clearer and specifically focuses limited resources on situations for which there is a reasonable potential for a discharge. Limited resources should not be consumed in developing flow rate, direction and quantity predictions in the SPCC Plan for situations without a reasonable potential for discharge to navigable waters.” (67, 85) The provision is useless and should be deleted. (28, 101, 164)

Editorial suggestions. We should replace *possible spill pathways* with *most likely spill pathways to navigable waters*. We should explain the need for this provision and allow public review of this explanation before publishing the final rule. The realm of potential pathways would be increased by the inclusion of the EPA-recommended 25-year storm event. Our proposal would encourage an exploration and production (E&P) operator to exclude non-oil-storage portions of a facility in the Plan, which would increase the “oil pollution potential.” (L12)

We should replace “direction...of oil...of each major type of failure” with the requirement that the owner or operator include a prediction of “the most likely spill to reach navigable waters.” (L12)

Electrical equipment. Facilities with electrical equipment should be exempted from this analysis. (125)

Failure factors. The rule should clarify how detailed the analysis of potential spill pathways should be. (156)

Flowlines or gathering lines. Discharge estimates for these lines would be meaningless and requested that we clarify the provision. (28) For flowlines or gathering lines, it is impossible for the owner or operator to estimate the quantities of oil potentially discharged. (101)

Major failures. “First, EPA has not defined a major type of failure and would need to give the regulated community some guidance in this area. If it were tuned to bulk storage tanks, as defined above, this could address tank failures which have the capability of releasing 20,000 or more gallons.” (164)

Obvious scenarios. “This provision is totally unnecessary insofar as the Appalachian producers are concerned. It is overly involved for small operators to imagine every conceivable type of failure, and calls for a creative imagination in a place where such is not required. Only obvious scenarios, such as tank rupture or leakage are necessary considerations for anticipating cleanup efforts.” (28, 31, 101, 175)

Small discharges. “Section 112.7(b) should be clarified to emphasize that the focus of the SPCC Plan should be on assuring that any release is prevented and mitigated, not just ‘major’ releases. Facilities routinely experience and manage smaller releases, while major spills are comparatively rare.” (175)

Spill history. We should clarify whether we intend to require predicting the number and degree of discharges based upon spill history. Predictions based on this history would be unreliable, and we should delete the provision. (143)

Response: *Applicability.* We agree with the commenter that current language is clearer and will retain it. We therefore modified the first sentence contained in the proposed rule. We agree that the Plan must only discuss potential failure situations that might result in a discharge from the facility, not any failure situation. The rule requires that when experience indicates a reasonable potential for failure of equipment, the Plan must contain certain information relevant to those failures. “Experience” includes the experience of the facility and the industry in general.

We disagree that the requirement is too difficult for owners or operators of small or mobile facilities, or of flowlines or gathering lines, or of electrical equipment facilities, or other users of oil. We believe that a Professional Engineer may evaluate the potential risk of failure for the aforementioned facilities and equipment and predict with a certain degree of accuracy the result of a failure from each. We note that since we have raised

the regulatory threshold, this requirement will not be applicable to many smaller facilities.

We also disagree that our proposal would encourage an exploration and production (E&P) operator to exclude non-oil-storage portions of a facility in the Plan, which would increase the “oil pollution potential.” A description of the possible direction and rate of flow of discharged oil includes any area over which that oil may flow, including non-oil portions of a facility.

Editorial suggestions. In final §112.7(b), we use the term “a prediction of the direction, rate of flow, and total quantity of oil which could be discharged” instead of the term “possible spill pathways.”

Failure factors. To comply with this section, you need only address “major equipment” failures. A major equipment failure is one which could cause a discharge as described in §112.1(b), not a minor failure possibility. To help clarify the type of equipment failures the rule contemplates, we have added examples of other types of failures that would trigger the requirements of this paragraph. Such other equipment failures include failures of loading/unloading equipment, or of any other equipment known to be a source of a discharge. The analysis required will depend on the experience of the facility and how sophisticated the facility equipment is. If your facility has simpler equipment, you will have less to detail. If you have more sophisticated equipment, you will have to conduct a more detailed analysis. If your facility’s experience or industry experience in general indicates a higher risk of failure associated with the use of that equipment, the analysis must also be more detailed. This rationale and analytic detail are also applicable to electrical equipment facilities and other facilities that do not store oil, but contain it for operational use. Again, the required explanation will be tailored to the type of equipment used and the experience with that equipment.

Spill pathways. The level of analysis concerning spill pathways will depend on the geographic characteristics of the facility’s site and the possibility of a discharge as described in §112.1(b) that equipment failure might cause. However, the Professional Engineer should focus on the most obvious spill pathways. The level of analysis required for prediction of spill pathways is that which may be reasonably foreseen, given the physical location of the facility. We have not included a 25-year storm event standard in the rule, so that calculation may not be applicable.

Because this information is facility specific, the owner or operator of a mobile facility will not be able to detail spill pathways in the general Plan for the facility each time the facility moves. However, the owner or operator must provide management practices in the general Plan that provide for containment of discharges in spill pathways in a variety of geographic conditions likely to be encountered. In case of a discharge at a particular facility, the owner or operator would then take appropriate action to contain or remove the discharge. For example, the Plan may provide that a rig must be positioned to minimize or prevent discharges as described in §112.1(b); or it may provide for the use of spill pans, drip trays, excavations, or trenching to augment discharge prevention.

X - D: Secondary containment - §112.7(c)

Background: Section 112.7(c) of the current rule lists appropriate containment and diversionary structures, or equipment, and among other things requires that dikes, berms or retaining walls be “sufficiently impervious to contain spilled oil.” In 1991, we proposed to revise §112.7(c) to require that the entire containment system, including the walls and floor, must be impervious to oil for 72 hours.

Comments: *Applicability.*

Electric utilities. “Specifically, the Agency has recognized that it is often impracticable to provide at electrical substations the secondary containment required by proposed section 112.7(c).” (125)

Flowlines, fired vessels, pressured process vessels. “A statement should be included in the preamble to clarify that section 112.7(c) does not require dikes around flowlines, fired vessels or pressured process vessels at onshore producing facilities. Industry’s current practice is to construct dikes primarily around storage tanks. We think that this constitutes ‘good engineering practice’.” (125, 133)

Heavy oils. The requirement should not apply to tanks holding No. 5 and No. 6 fuel oils and asphalts. (54)

Mining sites. “The proposed containment requirements will be excessive for most mining operations and will require redesign in many instances with little resultant net environmental benefit.” (35)

Mobile facilities. “Many of these tanks are moved from location to location on a daily basis. Many are too small to require a SPCC Plan or located at a site with sufficient oil capacity to require a SPCC Plan. Secondary containment may not be feasible in these situations.” (190)

Phase-in. We should adopt a phased-in approach so that owners or operators would not have to comply immediately with this new provision. (31, 182)

Production facilities. We should exempt production facilities, and allow a contingency plan instead. (28, 31, 86, 165)

Underground piping. We should clarify that underground piping is not subject to the rule’s secondary containment provisions. (71)

Contingency planning or containment.

Contingency plan alternative. We should revise the provision to allow owners or operators to use contingency planning in lieu of diking tanks or other equivalent measures. (110)

No equivalent. We should place greater emphasis on secondary containment as an oil storage method that has no equivalent. (121)

Editorial suggestions.

Primary containment system. We should define *primary containment system*. (71)

Surface waters. We should define the term *surface waters*. We should change *surface waters* to *navigable waters* to be consistent with the Clean Water Act. (54, 58, 67, 91, 133, 167, 175)

Floors. The impervious requirement should apply only to horizontal releases and not vertical releases, because vertical releases (releases into the ground) do not pose a risk to navigable waters. (48) We should omit any reference to containment “floors” in the final rule, because the purpose of the regulation is to prevent discharge to surface waters and not to ground water. (1155 (1993 commenter))

Impermeability.

Support for 72-hour standard. “Not only is this provision essential to the protection of surface water, it will provide some protection for groundwater. Improperly constructed dikes have resulted in several groundwater pollution problems of significant extent in this state. The Department has recently revised its rules to require relatively impervious dike structures at all sites storing any substance likely to cause pollution of a water of this state. No exemptions to this requirement should be granted because of facility size or quantity of oil stored.” (4, 143, 185, L17).

Editorial suggestion. We should revise the standard as “impervious to oil and water for 72 hours.” (80)

Opposition to 72-hour standard. (11, 25, 31, 35, 42, 48, 57, 66, 67, 71, 72, 74, 75, 78, 85, 86, 91, 101, 102, 110, 114, 116, 125, 155, 156, 164, 170, 173, 175, 177, 182, 184, L3, L30).

Current standard is adequate. The current “sufficiently impervious” standard was adequate. (31, 35, 42, 71, 78, 86, 92, 113, 155, L3)

No environmental benefit. If adopted, the 72-hour impermeability standard would require owners or operators to modify existing secondary containment structures. Owners or operators would spend a significant amount of money on these

modifications for no additional environmental benefit. (11, 25, 28, 34, 35, 48, 58, 75, 90, 95, 101, 102, 110, 113, 139, 165, 167, 173, 175, 182, 1155 (1993 comment))

Alternate standards.

§112.8(c) standard. We should use the language proposed in §112.8(c)(2) in §112.7(c). The §112.8(c)(2) approach would permit some contamination of the containment system, without sanctioning an oil discharge to surface waters. (34, 77)

Containment instead. The rule should address containment rather than impermeability; the reason for a containment structure is to keep a discharge from reaching navigable waters. (25, 34, 74, 116, 164, 170, L30)

Containment or cleanup. We should give facilities a choice between renovating containment to be impervious for 72 hours and providing for the expedient clean-up of a spill. (90)

Liners. “In lieu of a requirement for total imperviousness, specify acceptable liner materials such as compacted clay, plastic, asphalt or concrete, and corresponding levels of acceptable permeability.” (107)

Monitoring. “While supporting this clarification, it should also be recommended that if a truly impervious containment is not provided, a check should be made of available geological records and documents, site conditions, etc., to assure that such conduits that may cause substantial migration of free product are appropriately monitored for discharges.” (76)

Alternate time frames.

24 hours, manned facilities. Suggests language requiring the containment system to “be constructed to contain released oil for at least 24 hours” if it is “normally attended during typical work hours.” “A requirement this strenuous is unnecessary in situations where personnel are present during a routine workweek.” (183)

More than 24 hours, unmanned facilities. “As an alternative, this requirement should be revised such that it is applicable only to facilities that go unmanned for more than 24 hours at any one time.” (102)

36 hours and inspections. In addition to the 72 hour standard, EPA should allow “alternate requirements which would allow for expedient cleanup of spills, e.g., within 36 hours, and/or an increased frequency of inspections.” (90)

72 hours; “As soon as practicable.” “If the potential exists for the oil to reach surface waters, then immediate cleanup within 72 hours would be appropriate. For all other types of oil spills, it could be required that clean up measures should be initiated as soon as practicable with proper containment measures in place within 72 hours.” (22, 125, L20)

“Duration of the emergency response.” Containment structures should be “sufficiently impervious to retain oil for the duration of the emergency response.” (75, 87)

No time limit. “The inclusion of a specific time frame is not necessary. While API would agree that 72 hour retention may be a realistic goal in most cases, we discourage the use of any specified amount of time applied universally and instead recommend that the SPCC regulations establish the intent and allow the regulated community the opportunity to meet that intent.” (25, 66, 67, 78, 85, 91, 95, 102, 133, 175)

Applicability.

Attended facilities. The 72-hour standard is unnecessary for facilities that are attended 24 hours a day, because facility employees will find a spill within a few hours. (39, 48, 62, 87, 95, 102, 124, 125, 155, 173, 175, 182, L8, L30) This requirement should apply only to those facilities that are unattended. (183, L18) We should require the 72-hour standard only at a facility that is unmanned for more than 42 consecutive hours. (182)

Environmentally sensitive areas. Only owners or operators of facilities in environmentally sensitive areas (e.g., wetlands) should have to meet the 72-hour standard. (114)

New facilities only. The 72-hour impermeability requirement should apply to new facilities only. (165, 182, 192)

Calculation of 72 hours. Asks when 72 hours begins to run, from discovery of the discharge or time of occurrence. (82)

Clarification of “impervious” needed. We should further define “impervious to oil for 72 hours” in the proposed standard. (9, 34, 58, 67, 68, 70, 71, 76, 81, 83, 87, 91, 92, 95, 98, 101, 107, 114, 115, 117, 125, 133, 179, 182, 187, L2, L12) We should define *impervious* in terms of engineering standards. (27, 57, 87, 101, 114, 135, 175, 177, 186, 190)

Good engineering practice. We should revise the standard to make clear that the impervious determination should be based on good engineering practice. (125)

Showing impermeability. Asks how to prove that facility secondary containment systems are impervious. (10, 28, 58, 66, 101, 113, 125, 155, 156, 165, 179, 190) It would be too costly to prove that secondary containment systems were impervious. (28, 90, 101, 113, 165, 182)

Methods of secondary containment.

Alternative structures. Alternative secondary containment structures are impracticable at small facilities. (182)

Earthen structures. “An arbitrary requirement that a dike be ‘impervious’ could be interpreted to require replacement of almost all of the existing containment systems for production locations, most of which have earthen dikes. Such containment systems prevent oil from migrating offsite to waters but may not be completely ‘impervious.’ Given the low level of risk presented by such facilities, with their typically low volumes of storage, IPAA does not believe that the proposed requirements are justified.” (28, 31, 34, 39, 67, 74, 75, 77, 86, 91, 101, 107, 110, 113, 133, 164, 165, 167, 186, 187, 195, L30)

Factory fabricated. We should clarify whether forms of construction with factory fabricated secondary containment are equivalent forms of construction. (140)

Flexibility. We should maintain flexibility in allowing owners or operators to use one or more secondary containment systems. (39, 54, 70, 71) We should provide owners or operators flexibility to meet the protection standard in a way that is cost effective to them. (184)

Sorbents or booms. We should remove sorbent materials or booms from the list of acceptable secondary containment structures because they are not a substitute for impervious dikes and impoundment floors. (111)

Sump pump or catchment basin. Sump pumps, catchment basins, or other methods listed in §112.9(b)(2) might be sufficient. (28, 31, 167)

Response: *Applicability of requirement.* Secondary containment is best for most facilities storing or using oil because it is the most effective method to stop oil from migrating beyond that containment. We believe that secondary containment is preferable to a contingency plan at manned and unmanned facilities because it prevents discharges as described in §112.1(b). At unmanned facilities, it may be even more important because of the lag in time before a discharge may be discovered. Notwithstanding what may be difficult terrain, we believe that some form of secondary containment is practicable at most facilities, including remote production facilities. In fact, it may often be more feasible in remote or rural areas because there are fewer space limitations in such areas. For example, at some remote mobile or production facilities, owners or operators dig trenches and line them for containment or retention of

drilling fluids. Technologies used at offshore facilities to catch or contain oil may also sometimes be used onshore.

While some types of secondary containment (for example, dikes or berms) may not be appropriate at certain facilities, other types (for example, diversionary systems or remote impounding) might. However, we recognize and repeat, as we noted in the 1991 preamble, that some or perhaps all types of secondary containment for certain facilities with equipment that contain oil, such as electrical equipment, may be contrary to safety factors or other good engineering practice considerations. There might be other equipment, like fired or pressurized vessels, for which safety considerations also preclude some or all types of secondary containment.

Some facilities or equipment that use but do not store oil may or may not, as a matter of good engineering practice, employ secondary containment. Such facilities might include wastewater treatment facilities, whose purpose is not to store oil, but to treat water. Other facilities that may not find the requirement practicable are those that use oil in equipment such as hydraulic equipment. Similarly, flowlines must have a program of maintenance to prevent discharges. See §112.9(d)(3). The maintenance program may or may not include secondary containment. Owners or operators of underground piping must have some form of corrosion protection, but do not necessarily have to use secondary containment for that purpose.

As stated above, for a facility where secondary containment is not practicable, the owner or operator is not exempt from the requirement, but may instead provide a contingency plan and take other measures required under §112.7(d). For most facilities, however, including small facilities, mobile facilities, production facilities, mining sites, and any other facilities that store or use oil, we believe that secondary containment is generally necessary and appropriate to prevent a discharge as described in §112.1(b). Without secondary containment, discharges from containers would often reach navigable waters or adjoining shorelines, or affect natural resources.

Completely buried tanks. Completely buried tanks which are not exempted from this rule because they are subject to all Federal or State UST requirements are subject to the secondary containment requirement. We realize that the concept of freeboard for precipitation is inapplicable to secondary containment for completely buried tanks. The requirement for secondary containment may be satisfied in any of the ways listed in the rule or their equivalent.

Contingency planning or containment. A contingency plan should not be used routinely as a substitute for secondary containment because we believe it is normally environmentally better to contain oil than to clean it up after it has been discharged. Secondary containment is intended to contain discharged oil so that it does not leave the facility and contaminate the environment. The proper method of secondary containment is a matter of good engineering practice, and so we do not prescribe here any particular method. Under part 112, where secondary containment is not practicable, you may deviate from the requirement, provide a contingency plan following

the provisions of 40 CFR part 109, and comply with the other requirements of §112.7(d). For bulk storage containers, those requirements include both periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping. You must also provide a written commitment of manpower, equipment, and materials to expeditiously control and remove any quantity of oil discharged that may be harmful.

Double-walled or vaulted tanks. The term “vaulted tank” has been used to describe both double-walled tanks (especially those with a concrete outer shell) and tanks inside underground vaults, rooms, or crawl spaces. While double-walled or vaulted tanks are subject to secondary containment requirements, shop-fabricated double-walled aboveground storage tanks equipped with adequate technical spill and leak prevention options might provide sufficient equivalent secondary containment as that required under §112.7(c). Such options include overfill alarms, flow shutoff or restrictor devices, and constant monitoring of product transfers. In the case of vaulted tanks, the Professional Engineer must determine whether the vault meets the requirements for secondary containment in §112.7(c). This determination should include an evaluation of drainage systems and of sumps or pumps which could cause a discharge of oil outside the vault. Industry standards for vaulted tanks often require the vaults to be liquid tight, which if sized correctly, may meet the secondary containment requirement.

There might also be other examples of such alternative systems.

Editorial suggestions.

Primary containment system. In response to the commenter’s question, we note that a primary containment system is the container or equipment which holds oil or in which oil is used.

Surface waters. We do not use the term “surface waters” in the final rule. We revised the proposed phrase, “escape to surface waters” to read “escape from the containment system” to reflect more clearly the intent of the rule that secondary containment should keep oil from escaping from the facility and reaching navigable waters or adjoining shorelines.

72-hour impermeability standard. We are withdrawing the proposal for the 72-hour impermeability standard and will retain the current standard that dikes, berms, or retaining walls must be sufficiently impervious to contain oil. We agree with commenters that the purpose of secondary containment is to contain oil from escaping the facility and reaching the environment. The rationale for the 72-hour standard was to allow time for the discovery and removal of an oil spill. An owner or operator of a facility should have flexibility in how he prevents a discharge as described in §112.1(b), and any method of containment that achieves that end is sufficient. Should such containment fail, the owner or operator must immediately clean up any discharged oil.

Similarly, because the purpose of the “sufficiently impervious” standard is to prevent discharges as described in §112.1(b), dikes, berms, or retaining walls must be capable

of containing oil and preventing such discharges. Discharges as described in §112.1(b) may result from direct discharges from containers, or from discharges from containers to groundwater that travel through the groundwater to navigable waters or adjoining shorelines. Effective containment means that the dike, berm, or retaining wall must be capable of containing oil and sufficiently impervious to prevent discharges from the containment system until it is cleaned up. The same holds true for container floors or bottoms; they must be able to contain oil to prevent a discharge as described in §112.1(b). However, “effective containment” does not mean that liners are required for secondary containment areas. Liners are an option for meeting the secondary containment requirements, but are not required by the rule.

If you are the owner or operator of a facility subject to this part, you must prepare a carefully thought-out Plan in accordance with good engineering practice. A complete description of how secondary containment is designed, implemented, and maintained to meet the standard of sufficiently impervious is necessary. In order to document that secondary containment is sufficiently impervious and sufficiently strong to contain oil until it is cleaned up, the Plan must describe how the secondary containment is designed to meet that standard. A written description of the sufficiently impervious standard is not only necessary for design and implementation, but will aid owners or operators of facilities in determining which practices will be necessary to maintain the standard of sufficiently impervious. Control and/or removal of vegetation may be necessary to maintain the impervious integrity of the secondary containment. Repairs of excavations or other penetrations through secondary containment will need to be conducted in accordance with good engineering practices in order to maintain the standard of sufficiently impervious. The owner or operator should monitor such imperviousness for effectiveness, in order to be sure that the method chosen remains impervious to contain oil.

We note that we have withdrawn the proposed 72-hour standard, and afford various secondary containment options, including earthen dikes and diked areas, if they contain and prevent discharges as described in §112.1(b). Therefore, there are no new costs. We disagree with the commenters who asserted that we underestimated the cost to comply with the secondary containment and truck loading area requirements. The revised rule, like the current rule, does not require a specific impermeability for dikes and does not require a specific method of secondary containment at loading areas, and this flexibility is reflected in our cost estimates. We noted in our 1991 Supplemental Cost/Benefit Analysis that secondary containment for bulk storage tanks is estimated to cost \$1,000 for small facilities; \$6,400 for medium facilities; and \$63,000 for large facilities. Unit cost estimates were developed for a broad mix of facilities (e.g., farms, bulk petroleum terminals) in each size category by experienced engineers with firsthand knowledge of the Oil Pollution Prevention Regulation and the operations of onshore SPCC-regulated facilities. Because our cost estimates must be representative of the many types of facilities that are regulated, they will underestimate the costs for some facility types and overestimate the costs for others. Facilities were assumed to construct secondary containment systems of impervious soil capable of holding 110 percent of the largest tank. In that analysis, we estimated that 78 percent and 88

percent of the regulated community were already in compliance with these requirements, respectively, and would not be affected by the proposed rule change.

Since we last performed these analyses, API has issued several industry standards, including API 653 and 2610, which address many of the provisions in the SPCC rule. As a result, the final rule relies on current industry standards and practices, where feasible. In the final rule, we withdrew the proposed 72-hour impermeability standard for secondary containment and maintained the current requirement that dikes, berms, and oil retaining walls must be *sufficiently impervious* to contain oil. As a result, the final rule reflects current industry standards and we assume poses no additional requirements on industry.

Industry standards. Industry standards that may assist an owner or operator with secondary containment include: (1) NFPA 30; (2) BOCA, National Fire Prevention Code; and, (3) API Standard 2610, “Design, Construction, Operation, Maintenance, and Inspection of Terminal and Tank Facilities.”

Methods of secondary containment. We disagree that we should remove sorbent materials and booms from the list of acceptable secondary containment structures. The appropriate method of secondary containment is an engineering question, and therefore we do not prescribe any particular method. Double-walled piping may be an option, but is not required by these rules. Earthen or natural structures may be acceptable if they contain and prevent discharges as described in §112.1(b), including containment that prevents discharge of oil through groundwater that might cause a discharge as described in §112.1(b). What is practical for one facility, however, might not work for another. If secondary containment is not practicable, then the facility must provide a contingency plan following the provisions of 40 CFR part 109, and otherwise comply with §112.7(d).

Sufficient freeboard. See the Response to Comments in §112.8(c)(2) for a discussion of this topic.

X- E Contingency planning

X-E-1 - 1991 and 1993 proposals

Background: *1991 proposal.* Current §112.7(d) requires that, when an owner or operator determines that secondary containment is impracticable, he must demonstrate this impracticability and prepare a strong oil spill contingency plan following the provisions of 40 CFR part 109. In 1991, we proposed several new requirements in §112.7(d). We proposed language clarifying that the owner or operator must submit the contingency plan to the Regional Administrator (RA) for approval. Further, we replaced the reference to 40 CFR part 109 with a list of basic requirements for an oil spill contingency plan. We proposed language requiring that the owner or operator make the contingency plan a stand-alone section of the Plan; and, that he not rely upon response methods other than containment and physical removal of oil from the water (e.g., not rely on dispersants or other chemicals), unless the RA approved such response methods. We also asked for general comments on Phase Two contingency planning, and specific comments and supporting data on contingency planning needs.

Under §112.7(d)(2) of the current rule, the owner or operator of a facility without secondary containment must provide a written commitment of manpower, equipment, and materials required to expeditiously control and remove any harmful quantity of discharged oil as part of his contingency plan. In 1991, we proposed in §112.7(d)(2) a recommendation that the facility owner or operator consider factors such as financial capability in making the written commitment of manpower, equipment, and materials.

1993 proposal. In 1993, we modified the 1991 proposal for a facility that lacks secondary containment to require a facility response plan as described in §112.20, instead of the specific requirements proposed in 1991. The response plan would not be submitted to the Regional Administrator for his review, unless otherwise required, but would be maintained at the facility with the SPCC Plan.

Comments: *Support for proposal.* Support for proposal for elementary contingency planning requirements. (61, 91, 175) Support for contingency planning as an alternative when secondary containment is impracticable. (90, 125) We should separate prevention and response plan rules. (121)

Expanded requirements. “3M believes that requirements for even elementary contingency plans should be expanded during this rulemaking to include additional factors. ... Accordingly, 3M believes the SPCC regulation should expressly require the calculation of a worst case scenario as part of each contingency plan. ... 3M believes the SPCC regulation should require each contingency plan to document the availability of enough sorbent material and other equipment to manage a worst case spill. ... The regulation should state that the plan must provide for: employee training in implementation of the plan, including practice drills; availability of protective gear for all employees who may be called upon to respond to a spill; and, timely restocking of sorbents and

protective gear after use. 3M also supports EPA's plan to develop more detailed requirements for contingency plans, including vulnerability analyses and event and fault tree analyses, as part of the Phase Two rulemaking." (61, 107)

Response planning and 1993 contingency planning proposal - Phase II.

Leak detection. At no time should we require installing leak detection systems or conducting vulnerability, and event and fault tree analyses at a facility with adequate secondary containment. (51, 57, 67, 155, 191) In the Phase Two regulations, we should require owners or operators to install these systems for all SPCC facilities, because secondary containment could not be effective for an underground spill and early detection should be a priority. (L1)

Performance standards. We should avoid making the Phase Two planning standards like performance standards. We should not initiate an enforcement action against an owner or operator who failed to follow "a script or scenario laid down during the planning process." (133)

Requirements premature. "API opposes as premature, facility-specific contingency plan information needs (i.e., discovery of a spill, emergency notification procedures, name of the spill response coordinator, procedures for identifying personnel and equipment that may be needed, available equipment lists, available personnel lists, an identification of hazards, a vulnerability analysis, and an event and fault tree analysis.) Until EPA fully defines, in the Phase Two rulemaking, the scope and limitation of these terms, justifies the informational needs in terms of protection of human health and the environment, and demonstrates that it is statutorily authorized to collect such information, it is premature to require it at this time. Area Committees, as mandated by the OPA, will be developing this information directly." (67) "The Agency's position appears to be that specific contingency planning requirements will be developed in its Phase II rulemaking. However, this is of little help to facilities that must develop contingency plans to meet Phase I requirements. Therefore, we recommend that the Agency defer the requirement to prepare contingency plans until promulgation of the Phase II rules." (125) We should require contingency planning only as part of Phase Two for facilities with the potential to cause substantial harm. (L12)

Secondary containment, not a contingency plan. "New York State does not accept contingency plans in-place of a secondary containment system. We recommend that all facilities threatening ground or surface waters have secondary containment facilities." (111)

Vulnerability analysis. The discussion of vulnerability, event and fault tree analyses is confusing in connection with the actual proposal in the Phase One rulemaking. (34) "Such analyses should not be required for facilities with secondary containment. Furthermore, if EPA should require these analyses, the

analyses should encompass readily available information and EPA should use only clearly understood criteria in asking for information.” (57, 89, 101, 107, 114, L15).

Downstream water suppliers. “It is proposed that, under Phase II, a site- specific contingency plan will include a vulnerability analysis, one element of which would be notification of drinking water suppliers [downstream]. Pennsylvania currently has such a requirement that could be considered to have a flaw. The Pennsylvania requirement is that oil storage facilities must identify water users for 20 miles downstream, and update that list every year. Because the primary source of such information is at offices of each county, the demands on the facilities and county offices is excessive. In addition, facilities may not identify a new water user for nearly a year.” (76)

Response: *Support for proposal.* We appreciate support for the proposal, but modified that proposal in 1993. See the preamble to today’s final rule and section 4 of the 1993 Comment Response Document for a discussion on contingency planning. See below for comments related to the extant 1991 proposal.

Response planning and 1993 contingency planning proposal - Phase II. For an in-depth discussion of issues in the Phase Two rulemaking, see the FRP preamble and final rule (59 FR 34070, July 1, 1994), the Phase Two docket (SPCC-2P), and the preamble to today’s final rule. See the preamble to today’s final rule, section 4 of the 1993 Comment Response Document for a discussion on contingency planning, and sections X-E, F, and G of this document.

X-E-2 General - §112.7(d)

Background. In 1991, we proposed to add language to §112.7(d)(1) listing the basic requirements for an oil contingency plan, including the phrase “and such other information as required by the RA.”

Comments: *Additional information.* This language is too broad and would subject facilities to unknown regulation. We should clearly specify what additional information would be required by the RA or change the language to state “such other information as the RA may reasonably require.” (103) The contents should include at least the same requirements as those found in the Oil Pollution Act (OPA) amendments to the Federal Water Pollution Control Act (FWPCA). (171)

Applicability.

Aboveground tanks. Proposed §112.7(d) should be applicable to fixed aboveground tanks only. (102)

Buried piping, buried tanks, portable tanks. Questions whether it was our intent to require facilities “with buried piping, buried tanks, or portable tanks for which

secondary containment cannot be provided” to prepare and submit an SPCC Plan. (102)

Electrical equipment. “The electric utility strongly supports the inclusion in the SPCC rules of an alternative to secondary containment/drainage control requirements where such controls are demonstrated to be impracticable. This provision adds needed flexibility to the rule and again allows the owner or operator to use good engineering practices in adapting the goals of the SPCC program to unusual facilities. As the Agency has recognized, secondary containment is impracticable at many electric utility substations.” (125)

FRP facilities. Re §112.7(d): “When response plans are to be required of all facilities, this paragraph should be deleted.” (121)

Large facilities. “Suggest that contingency plan for “large facilities” only be provided to Regional Administrator.” (62)

Production facilities. “Facility specific contingency plans are not practicable in many cases, particularly as they relate to onshore oil production operations. The profitability of these operations, especially stripper operations, would be utterly destroyed by the costs associated with preparation, implementation, review, revision, and other work associated with contingency planning.” (42, 58)

Production flowlines and trunklines. “Language should be included that excludes production flowlines and trunklines from this requirement. At most production facilities, dikes are installed around tank batteries, but not around flowlines because it is impractical to do so. As written, the regulation would require submission of spill contingency plans for all such facilities.” (167)

Rack to tank piping. “Proposed section 112.7(d) does not specifically address pipes running from the terminal rack to a tank(s), that will be by necessity outside of secondary containment. IFTOA believes that the facility should maintain a contingency plan to address potential discharges from such pipes reviewed and certified by the PE.” (54)

Clarifications.

Contingency plan vis-a-vis Facility Response Plans. Asks if we intend the terms *facility specific response plan* and *contingency plan* as used in the preamble to mean the same thing. (54)

Costs. Contingency planning is not practicable because the costs are too high. However, these commenters did not provide specific cost estimates. (42, 101, 110, 113, 114, L15) We should “be sensitive to the interest and concerns” of small businesses in developing the Phase Two rule. (48) “It is recommended that the Agency’s current strategy of requiring elementary contingency planning steps be continued for SPCC Plans for small facilities.” (101)

Dispersants. “While it is desirable to obtain approval from the Regional Administrator before using dispersants, NJDEPE is concerned about how state approvals of such use will be handled. NJDEPE’s rules presently require approval of either this department or the federal on-scene coordinator. Would this approval be sufficient under this proposal?” (147)

Disposal of recovered oil and other materials.

Favors proposal. “We strongly agree that provisions for waste disposal should be addressed in contingency plans, including provisions for the temporary storage of recovered oil and oily waste.” (193)

Opposes proposal. “The SPCC Plan should focus on spill control and countermeasures rather than disposal of discharged substances, since the disposal of recovered oil, used sorbents, and other materials is regulated by state regulations, by RCRA, or existing federal regulations.” (L30)

EPA review and approval. “It is not clear from the proposal whether such a contingency plan must be reviewed and approved by the Registered PE or the RA of EPA. Review by the RA is duplicative, time-consuming, and unnecessary.” (54) Our proposed requirement that owners or operators submit contingency plans to the RA would require the RA to review and approve a substantial number of plans. (58) We should delete the contingency plan submittal requirement because the RA already has the authority under §112.4 to call for Plans from those facilities that may be defined as “problem facilities.” (101) “It does not state that it must be provided to the Regional Administrator any more than the SPCC Plan must be provided. It must be provided if requested by the Regional Administrator, but the preamble language infers that submittal of every contingency plan to the RA is automatic upon being developed.” (165, L15)

Electrical equipment facilities. Questions whether we would be able to both review and approve all submitted plans within an acceptable time frame and maintain program credibility. (111) “It is unnecessarily burdensome and expensive, however, to submit such plans to the Agency for numerous substations.” (161) “

Review times. “In addition, such a review process could result in project delays. If the Agency intends to pursue this requirement, the regulations should address a reasonable deadline (such as 30 days) that the Agency would have to review and approve the contingency plan.” (90, 161) We should clarify whether the contingency plan would be due to the RA within two months of the effective date of the final rule. We should allow owners or operators at least six months to update their existing SPCC Plans. (141)

Financial responsibility. The reference to “financial responsibility requirements” is superfluous. Equipment, personnel, and other spill-related expenses are operating expenses for most manufacturing entities, and would impose no financial responsibility. (162)

Formats.

Generic contingency plans (electrical substations). “Since all substations are very similar in design and spill response would be conducted by the same personnel, PEO suggests that use of more generic, area wide contingency plans be allowed for facilities such as substations.” (41)

HAZWOPER Plans. “The contingency plan requirement should be dropped for ‘small size facilities’ which have a HAZWOPER plan and trained response team.” (62, 152)

RCRA contingency plan. “The elements discussed that would make up the Contingency Plan are similar in nature to those that the RCRA regulations require for hazardous storage facilities. In an effort to minimize redundancy, the RCRA Contingency Plan should be allowed to be used in lieu of a separate Contingency Plan to satisfy this rule.” (87, 186)

Specific format. “Finally, we recommend the oil spill response plan required under 40 CFR 112.7(d) specify a specific format for its development. We recommend that the contents include at least the same requirements found in the OPA amendments to the FWPCA.” (171)

Stand alone section.

Should not stand alone. “If a discharge occurs, personnel may need to respond to operation and maintenance procedures, as well as responding to a cleanup. Referring to two sections for one discharge is not effective.” (38)

Should stand alone. “Maintaining the contingency plan as a separate section of the SPCC plan makes good operational sense. Large documents which contain non-essential information are seldom if ever used, and difficult to use.” (62, 190)

Location of contingency plan. We should require the owner or operator to keep the contingency plan on-site at the facility and available for the RA’s review during normal working hours. This would reduce the unnecessary administrative burden associated with submission of the contingency plan. (90)

Mandatory secondary containment. We should require secondary containment for all facilities threatening ground or surface waters. Contingency plans will not stop petroleum from reaching surface waters as effectively as “in-place properly designed and maintained secondary containment systems.” (111)

PE certification. Asks if it is necessary for a Professional Engineer to certify a contingency plan. (121)

Practicability. Our definition of *practicable* is not specific enough. We should provide guidance on *practicability*, otherwise, owners or operators may base practicability on the economics of preparing a contingency plan rather than installing prevention equipment. (1153 (1993 commenter))

Scope of the contingency plan. "...EPA should make clear that a contingency plan is required for that portion of the facility that is outside of secondary containment." (54)

Response: *Additional information.* We have modified the 1991 proposal by withdrawing proposed §112.7(d)(1). We also have withdrawn the 1993 proposal which would have required a response plan for a facility lacking secondary containment.

Applicability. Under the current rule, contingency planning is necessary whenever you determine that a secondary containment system for any part of the facility that might be the cause of a discharge as described in §112.1(b) is not practicable. This requirement applies whether the facility is manned or unmanned, urban or rural, and for large and small facilities. Facility components that might cause a discharge as described in §112.1(b) include containers, piping, valves, or other equipment or devices. Contingency planning is necessary for all facilities to avert and adequately respond to discharges as described in §112.1(b) regardless of facility size, if the facility lacks secondary containment. It is also necessary in areas historically not subject to natural disasters, because spills can also be caused by human error or mechanical failures.

Completely buried tanks. We note that completely buried tanks, as defined in §112.2, and connected underground piping, underground ancillary equipment, and containment systems that are subject to all of the technical requirements of 40 CFR part 280 or a State program approved under 40 CFR part 281 are not subject to part 112. 40 CFR 112.(d)(2)(i). Those tanks, piping, and ancillary equipment that remain subject to the SPCC program are therefore subject to contingency planning requirements in the appropriate case.

Electrical equipment. Any facility without secondary containment must prepare a contingency plan when secondary containment is not practicable. See the discussion under §112.7(d) in today's preamble. We disagree that the preamble language should be construed as granting a blanket impracticability determination to any facility (including facilities with electrical equipment). Such a determination is a facility-specific one.

FRP facilities. In response to comment, we have revised the rule to exempt from the contingency planning requirement any facility which has submitted a response plan under §112.20 because such a response plan is more comprehensive than a contingency plan following part 109.

We disagree that facility response planning is beyond our statutory authority, since it is a procedure or method to remove discharged oil. See section 311(j)(1)(A) of the CWA. However, while we disagree that such planning is expensive and lacking in environmental benefit, we agree that the current contingency plan arrangements which reference 40 CFR part 109 should be sufficient to protect the environment, and that a facility response plan as described in §112.20 is therefore unnecessary for a facility that is not otherwise subject to §112.20. We agree with the commenter that structures or equipment might achieve the same or equivalent protection as response planning for some SPCC facilities. Therefore, we are withdrawing that part of the 1993 proposal related to response planning in proposed §112.7(d)(1), but are retaining the current contingency planning provisions, which require a contingency plan following the provisions of 40 CFR part 109. We also believe that response plans should be reserved for higher risk facilities, as provided in §112.20.

Clarifications.

Contingency plan vis-a-vis Facility Response Plans. The terms *facility specific response plan* (FRP) and *contingency plan* have different meanings. The oil spill contingency plan is part of the SPCC Plan, required when secondary containment is not practicable at a facility. The FRP, addressed in §§112.20-21, is separate from the SPCC Plan, and is required only for a certain subset of SPCC facilities.

Costs. We note that we did not finalize the 1991 or 1993 contingency planning proposals. Thus there are no new costs for such planning.

Dispersants. We withdrew the proposed reference to the use of dispersants in §112.7(d) in 1993. Dispersant use is governed by subpart J of the NCP.

EPA review and approval. We have withdrawn the proposed submittal requirement because we believe it is sufficient that the contingency plan be available for on-site inspection. The contingency plan must be made a part of the SPCC Plan, and therefore, PE certification is required. In certifying the SPCC Plan, the PE attests that the owner's or operator's judgment of impracticability is correct.

Disposal of recovered oil and other materials. We agree that we should not require an owner or operator to address the disposal of recovered oil and other materials in a facility-specific contingency plan because this discussion is already required under §112.7(a)(v).

Financial responsibility. We have deleted the proposed recommendation concerning financial capability in making written commitments of manpower, equipment, and materials from the rules because we do not wish to confuse the regulated community by including discretionary requirements in a mandatory rule.

Formats. For §112.7 contingency planning requirements, an owner or operator may use a contingency plan prepared under other State or Federal authority as long as the plan follows part 109, or is supplemented so that it meets all of part 109's requirements.

Generic contingency plans (electrical substations). We agree that an owner or operator may create a multi-facility contingency plan. Such plan must include all elements required for individual contingency plans. It must also include site-specific information. However, the site specific information might be maintained in a separate location, such as a central office, or an electronic data base, as long as such information is immediately accessible to responders and inspectors. Where you place that site-specific information is a question of allowable formatting, an issue subject to RA discretion.

HAZWOPER Plans. The RA has discretion to accept any format that meets the requirements of 40 CFR part 109. Where such alternate format does not meet all of part 109's requirements, the owner or operator may supplement it so that it does.

RCRA. A contingency plan prepared under RCRA rules might suffice for purposes of the rule if the plan fulfills the requirements of part 109, and the PE certifies that such plan is adequate for the facility. If the RCRA contingency plan satisfies some but not all SPCC requirements, you must supplement it so that it does.

Specific format. It is unnecessary to specify a format for a contingency plan because we do not believe that there is a single format applicable to all facilities.

Stand alone section. We have withdrawn the proposed requirement that the contingency plan be a stand-alone section of the SPCC Plan. The owner or operator has flexibility to determine where to incorporate the contingency plan within the SPCC Plan.

Location of contingency plan. Today we have finalized the 1991 proposal that the Plan must be available at the facility if it is normally attended at least four hours per day, or at the nearest field office if it is not so attended. A Plan must always be available without advance notice, because an inspection might not be scheduled. You are not required to locate a Plan at an unattended facility because of the difficulty that might ensue when emergency personnel try to find the Plan. However, you may keep a Plan at an unattended facility. If you do not locate the Plan at the facility, you must locate it at the nearest field office.

Mandatory secondary containment. We agree that an in-place, properly designed, and maintained secondary containment system is the most effective way to prevent a discharge as described in §112.1(b). However, for certain facilities, secondary

containment may not be practicable because of geographic limitations, local zoning ordinances, fire prevention standards, or other good engineering practice reasons.

Part 109 requirements. In following the provisions of part 109, you must address the oil removal contingency planning criteria listed in 40 CFR 109.5 and ensure that all response actions are coordinated with governmental oil spill response organizations. The absence of secondary containment will place extreme importance on the early detection of an oil discharge and rapid response by the facility to prevent that discharge. Part 109 was originally promulgated to assist State and local government oil spill response agencies to prepare oil removal contingency plans in the inland response zone, where EPA provides the On-Scene Coordinator. The basic criteria for contingency planning listed in §109.5 apply to any SPCC regulated facility that has adequately justified the impracticability of installing secondary containment, irrespective of whether it is a government agency or the facility is located in the coastal (U.S. Coast Guard) or inland (EPA) response zone. Because the contingency plan involves good engineering practice and is technically a material part of the Plan, PE certification is required.

PE certification. The contingency plan is a technical part of the SPCC Plan which must be certified by a PE.

Practicability. We believe that it may be appropriate for an owner or operator to consider costs or economic impacts in determining whether he can meet a specific requirement that falls within the general deviation provision of §112.7(a)(2). We believe so because under this section, the owner or operator will still have to utilize good engineering practices and come up with an alternative that provides “equivalent environmental protection.” However, we believe that the secondary containment requirement in §112.7(d) is an important component in preventing discharges as described in §112.1(b) and is environmentally preferable to a contingency plan prepared under 40 CFR part 109. Thus, we do not believe it is appropriate to allow an owner or operator to consider costs or economic impacts in any determination as to whether he can satisfy the secondary containment requirement. Instead, the owner or operator may only provide a contingency plan in his SPCC Plan and otherwise comply with §112.7(d). Therefore, the purpose of a determination of impracticability is to examine whether space or other geographic limitations of the facility would accommodate secondary containment; whether local zoning ordinances, fire prevention standards, or safety considerations would prohibit the installation of secondary containment; or, if the installation of secondary containment would defeat the goal of the regulation to prevent discharges as described in §112.1(b).

Review of contingency plans. We note that the preamble to the 1993 proposed rule (at 58 FR 8841) suggested that response plans would not have to be submitted to the Regional Administrator unless “otherwise required by the rest of today’s proposed rule.” However, proposed §112.7(a)(2) would have required that the owner or operator submit to the Regional Administrator any Plan containing a proposed deviation, including a deviation for the general secondary containment requirements in §112.7(c). In any

case, we agree with commenters that the contingency plan (or any other deviation) should not have to be submitted to the Regional Administrator for his review and approval because we believe that it is sufficient that the contingency plan (or other deviation) be available for on-site inspection. We have therefore withdrawn that part of the proposal. See also the discussion on §112.7(a)(2).

Scope of the contingency plan. The contingency plan is applicable to the entire facility because it involves the capacity of the entire facility to prepare for and respond to a discharge as described in §112.1(b).

Small facilities. We disagree that contingency planning is too costly for small facilities. Such planning helps to save money when a discharge occurs. The requirements for contingency planning are fewer than the requirements for response planning. Response planning is required only for higher storage, higher risk facilities.

Written commitment. A “written commitment” of manpower, equipment, and materials means either a written contract or other written documentation showing that you have made provision for those items for response purposes. Such commitment must be shown by: the identification and inventory of applicable equipment, materials, and supplies which are available locally and regionally; an estimate of the equipment, materials, and supplies which would be required to remove the maximum oil discharge to be anticipated; and, development of agreements and arrangements in advance of an oil discharge for the acquisition of equipment, materials, and supplies to be used in responding to such a discharge. 40 CFR 109.5(c).

The commitment also involves making provisions for well defined and specific actions to be taken after discovery and notification of an oil discharge including: specification of an oil discharge response operating team consisting of trained, prepared, and available operating personnel; predesignation of a properly qualified oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations and who knows how to request assistance from Federal authorities operating under current national and regional contingency plans; a preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response actions; provisions for varying degrees of response effort depending on the severity of the oil discharge; and, specification of the order of priority in which the various water uses are to be protected where more than one water use may be adversely affected as a result of an oil discharge and where response operations may not be adequate to protect all uses. 40 CFR 109.5(d).

X - F: Integrity and leak testing - §112.7(d)

Background: Section 112.7(d) of the current rule sets out requirements for a facility when secondary containment is not practicable. In such cases, the owner or operator must explain the impracticability; provide a contingency plan following the provisions in 40 CFR part 109; and provide a written commitment of manpower, equipment, and

materials to control and remove any harmful quantity of discharged oil. In 1991, we proposed adding a requirement in §112.7(d) for the owner or operator of a facility without secondary containment to conduct integrity tests of tanks at least once every five years. We also proposed adding a requirement for integrity and leak testing of valves and piping at least once a year.

Comments: *Alternatives to integrity testing.*

Engineering evaluation instead. Rather than requiring an owner or operator to conduct integrity tests of underground piping, we should require an owner or operator to conduct an “engineering evaluation” of unprotected, underground piping to test its integrity. (67, 91)

Applicability.

Ancillary equipment. “..., because spills and leaks most commonly occur due to equipment failures related to piping, valves, and pumps, ATA recommends expanding the integrity test to cover ancillary equipment. The same 5-year and 10-year testing schedules proposed for tanks are reasonable for ancillary equipment.” (107)

Electrical equipment. “...this provision is impracticable because certain types of electrical equipment, such as underground transmission cable systems, cannot be integrity tested, while ones that can be tested, such as transformers, must be taken out of service to be tested. Moreover, this requirement is unnecessary because electrical equipment in service is constantly being tested because the equipment will fail if there is a leak.” (74, 125, 156, 158, 183, 189, 192) It is unnecessary and inappropriate to apply the §112.7(d) integrity testing requirements to oil-filled equipment, because typical substation transformers are protected by alarm systems sufficient to alert operators of leaks. Integrity testing this equipment would result in an unnecessary expense. (158) “This is another instance where a size differential could be used to exempt oil-filled electrical equipment from these inappropriate and unnecessary requirements.” (183)

Fixed aboveground piping. Proposed §112.7(d) should apply only to fixed aboveground piping that lacks secondary containment. It appears that §112.7(d) applies to aboveground and underground tanks, valves, and piping; and it is highly unlikely for buried tanks, piping, or valves to have secondary containment. Further, proposed §112.7(d) “defeats the discretionary testing schedule contained in §§112.8(c)(4) for buried metallic tanks and 112.8(d)(4) for buried piping.” (102)

Flowlines and gathering lines. “Further, the alternate to 40 CFR section 112.7(c) requires flow lines testing. The pressure test provision offer little advantage over normal flowline pressure, which is present at all times. Typically, flowline leaks are small and routine inspection at road crossings provides sufficient protection

from oil entering Waters of the U.S. However, the voluntary Contingency Plan requirement provides added protection.” (110) The required annual pressure testing of flowlines and gathering systems would be costly for small operators. We should exclude flowlines and gathering systems from the §112.7(d) testing provisions. (28, 31, 101,165, L15).

Impracticality. We should not require annual integrity leak testing of tanks where installation of secondary containment is impractical. Monthly visual inspection of tanks, valves, and aboveground piping provides adequate protection to the environment. (1155 (1993 commenter))

Phase-in. We should require tanks subject to §112.7(d) to comply with the provisions within five years of the promulgation date of the final rule and every five years thereafter. (125)

Production facilities. We should clarify whether secondary containment is inapplicable for offshore and coastal production facilities, and therefore, whether the proposed integrity testing requirements are necessary at such facilities. “In all other cases,” the integrity testing requirements should not be applicable to the production industry. (1199 (1993 commenter))

Small facilities.

Supports testing requirements. “The testing of tanks for integrity is needed. While most large corporations perform testing at some frequency, most smaller businesses do not. Exemptions because of size or quantity of oil stored should not be granted because the smaller facilities generally are more in need of testing.” (3, 4, 27, 95)

Opposes testing requirements. “EPA should make a distinction between large and small facilities, and should require integrity testing only on larger tanks such as those commonly located at complicated fuel distribution sites, commonly known as tank farms. Facilities which are primarily engaged in vehicle refueling operate above ground tanks which typically hold significantly less than that found at tank farms are suitable for visual inspections. EPA should realize that presently, there exists a limited amount of organizations which perform integrity tests on above ground tanks. If EPA were to promulgate an integrity test requirement on all aboveground tanks, many trucking facilities will find it difficult and expensive to identify appropriate testing agents.” (53, 70) Proposed §112.7(d) integrity testing requirements would be burdensome for small remote facilities. We should require integrity testing only at a facility with a storage capacity greater than 42,000 gallons and without the structures or equipment listed in proposed §112.7(c). (78, 145, L3) We should require integrity testing for facilities with a storage capacity greater than 100,000 gallons, and testing of valves and piping located directly above or on a pervious surface of such tanks. (90,1137 (1993 commenter)) The §112.7(d) requirement should apply only to

tanks with more than 660 gallons, because the costs of integrity testing smaller tanks outweigh the benefits. (125) The §112.9(d) provisions provide adequate environmental protection for small facilities. (145)

Tank failure. “Integrity testing at other than ten (10) year intervals should only be required if a tank failure has occurred within the last 5 years or the tank is used to store materials that are corrosive to the tank material. The small tanks at E&P operations are not likely to be susceptible to conditions requiring the five year inspection regimen.” (114)

Underground cable systems. Current technology does not allow an owner or operator to apply the secondary containment, inspection, and integrity testing requirements of the SPCC program to underground cable systems. (92, 98, 125) Proposed §112.7(d) is inappropriate for underground cable systems because there is no efficient system for integrity testing miles of interconnected piping. An owner or operator must keep underground cable systems in service. It is impossible for an owner or operator to develop a site-specific contingency plan for underground cable, since such systems cover large geographical areas. (125) We should not require an owner or operator to prepare a Plan for or integrity test cable systems. (164, 165)

Unprotected underground piping. We should limit annual integrity and leak test requirements to unprotected underground piping. (167)

Within structures, small tanks. “We propose an exemption for integrity testing of all tanks which: are contained within a building or have a maximum capacity of less than 2000 gallons; have all sides visible, and; which are visually inspected (along with any associated piping and ancillary equipment) at least monthly.” (54, 71, 78, 90, 101, 109, 110, 162, 167, 175)

Cost. Integrity testing is too costly. (28, 31, 54, 57, 58, 90, 102, 110; 1137, 1145 (1993 commenters).) The proposed requirement to test tanks without secondary containment annually would be costly and would restrict the owner’s or operator’s ability to conduct necessary inventories and to “meet supply and demand needs.” It would be impossible for the facility to operate if all tanks were taken out of service for testing every year. (25) We did not adequately consider the costs associated with the integrity testing for high pour point (e.g., 60°F) bulk storage tanks, because proposed §112.7(d) would require an owner or operator to completely drain and clean a tank. Such integrity tests would pose an unnecessary cost given the low risk of spills from such tanks. (90) We did not consider the cost of integrity testing substations and other oil-filled equipment in our economic impact analysis for the rulemaking. Such testing is impractical since owners or operators would have to test individual equipment pieces. (L2)

Discretionary testing. We should allow an owner or operator to determine the integrity of aboveground piping through frequent visual inspection and observation of the

product flowing through the line. We should allow an owner or operator to conduct visual inspections to comply with the §112.7(d) integrity testing requirement. (54) The requirement to conduct integrity testing applies to aboveground and buried tanks, piping, and valves should be discretionary. If the requirement were discretionary, the owner or operator could set a testing frequency based on facility-specific factors such as the facility's age, soil corrosiveness, and corrosion protection. Such a discretionary provision "defeats the discretionary metallic testing scheduled contained in §112.8(c)(4) for buried metallic tanks and §112.8(d)(4) for buried piping." (102)

Frequency of testing.

Support for proposal. General support for our proposal to specify time periods. (148, L1) Support for proposal to perform integrity testing of tanks once every five years at facilities without secondary containment. (95, 101, 102, L1, L2) Support for testing valves and piping once a year at such facilities. (80, 117) Support for integrity testing for cathodically protected piping every five years (167) and at the time of installation, modification, repair, and relocation (67).

Opposition to proposal. We should not require integrity testing of tanks every five years. (57, 78, 90, 101, 109, 128, L2, (1137, 1145, 1146, 1199 (1993 commenters))) Imposing these specific time periods is unnecessary and would provide "no improvement in the quality of SPCC plans." (155)

Cost. The proposed requirement to test tanks with secondary containment every five years would be costly and would obstruct handling necessary inventories. The proposed requirement would reduce the commenter's facility's ability to meet supply and demand, and it would be impossible to operate the facility if all tanks were out of service for testing every year. (25)

Excessive. "This requirement is not realistic for the oil and gas industry in Appalachia. It is recommended that the current language from §112.7(e)(5) be retained." (54, 67, 91, 95, 101, 102, 109, 167, 175, L2; (1137, 1145, 1146, 1199 (1993 commenters))). New tanks need less inspections than older ones, and we should only require an owner or operator to test a tank every five years after the first fifteen years of the tank's manufacturing date. (1165 (1993 commenter)) We should only require integrity testing less frequently than every 10 years only if a tank failure has occurred within the last five years, or if the tank contains corrosive materials. Small tanks at exploration and production (E&P) operation sites are unlikely to require integrity testing every five years. We should require integrity testing of pipes, valves, and fittings when corrosion or leakage has occurred or is "potentially severe." (114) We should only require an owner or operator to test valves and piping without secondary containment once every five years, and we should require an owner or operator to include in the Plan a schedule of visual inspections for such valves and piping. (95, L2) Such an approach would reduce the amount of waste generated by integrity testing and provide a reasonable integrity testing schedule. (95)

Maintenance instead. Routine inspection and maintenance of aboveground storage tanks and associated pipes, valves, and pumps is sufficient to eliminate the potential of a significant spill. We should require integrity testing only when the owner or operator detects something that may lead to a discharge. Inspections allow an owner or operator to determine whether maintenance and repairs are required to prevent a discharge. (54, 71, 78, 90, 101, 109, 110, 162, 167, 175)

Material repairs. Integrity testing is necessary only after material repairs. (78)

Mines. “For some small mining facilities, these testing requirements would be overly burdensome and quite expensive.... EPA should take into account the quantity of oil stored at a facility, and allow small facilities, with secondary containment, the right to inspect and monitor at the operator discretion, in accordance with good engineering practice.” (10)

Need for testing. We should develop an “administrative record” to determine the need for integrity testing. We should not require an integrity testing schedule in Phase One without stating what types of tests meet “statutory objectives.” (75)

Negative or no environmental impact. Integrity testing can negatively impact the environment. (90, 95) Annual testing would not significantly increase the level of environmental protection. (L2)

System failures. Integrity testing may exacerbate the probability of system failures. (67, 91, 1146, 1155 (1993 commenters))

Tank construction. We should base the frequency of integrity testing on such factors as the tank construction material and the nature of the material in the tank. (190)

Unnecessary. “This testing requirement would be costly to impose and lacks justification. Tanks with and without secondary containment deteriorate at the same rate and there is no reason to impose different testing requirements. The lack of secondary containment should be compensated for by site-specific contingency plans.” (57)

Weekly inspections instead. Instead of requiring annual integrity and leak testing, we should allow an owner or operator to conduct weekly inspections for oil leaks or spills during normal production facility operating conditions. There is a low risk of significant spills at production facility oil gathering systems because individual wells are located in a central processing storage facility. (1145 (1993 comment))

More frequent testing. We should permit more frequent inspection and monitoring than the rule requires. (87)

Guidance. We should set guidelines and recommendations in §112.7(d) for inspections and testing procedures and include proven and acceptable test methods in the regulation. We should include in §112.7(d) specific integrity testing procedures required for electrical equipment. (27, 80, L2)

Integrity testing. We should revise §112.7(d) to define *integrity testing*. (70) We did not define periodic *integrity testing* in the proposed rule, noting that we define the term in current §112.7(e)(2)(vi). (1149 (1993 comment))

Methods of testing.

Acoustic emission testing. We should allow for acoustic emission testing instead of hydrostatic testing as covered by API Standard 653. The tests are equally effective, but acoustic emission testing reduces wastewater production. (1135 (1993 comment))

API standards. “In lieu of frequent ‘integrity testing,’ we suggest that the EPA adopt the inspection portion of API 653, which allows up to 20 years between inspections. Integrity testing should be defined as the evaluation of a tank for serviceability. Short of a hydrostatic test, comprehensive tank inspection is the only method to evaluate the serviceability of a tank. The tank inspection method presented in API 653 details the tank components that should be examined and appropriate examination methods.” (1145, 1149 (1993 commenters))

Hydrostatic testing. We should allow an owner or operator to supplement hydrostatic testing with other inspection techniques while the tanks are in service and not being tested. This would allow an owner or operator to schedule tank outages when it is most convenient. (25)

“No appropriate technology.” There is no appropriate technology for testing fiberglass tanks or aboveground storage tanks. (62)

Pressure testing. Pressure testing could perforate a weakened section of piping, and compel an owner or operator to isolate and repair the section to avoid a corrosion-related leak. A corrosion-related leak could easily develop the day after the owner or operator performs pressure testing. (28, 31, 101, 165, L15) Frequent pressure testing of buried tanks and piping will create -- not prevent -- pollution, since owners or operators must conduct pressure testing with the oil contained in the system or must drain the oil and replace it with water. Pressure testing generates solid wastes, and that owners or operators must treat and dispose of the oily waste. (102) Pressure testing of tanks, valves, and equipment can weaken the integrity of a steel tank and contribute to failures of such tanks, valves, and equipment. (128)

Reference to §112.7(c). Our cross-reference to §112.7(c) is unclear. It is unclear whether the §112.7(c) reference refers to the existing or the proposed rule. Proposed §112.7(d) integrity testing requirement appears to refer only to tank batteries with dikes, berms, or retaining walls sufficiently impervious to contain spilled oil. (955 (1993 commenter))

Visual inspection.

Frequency.

Weekly inspection. We should allow an owner or operator to conduct daily or weekly visual inspections of valves and pipes. (1145,1199 (1993 commenters))

Monthly inspection. We should require an owner or operator to conduct a visual inspection of valves and aboveground piping at least once a month. (67, 91, 167)

Periodic inspection. “To require annual integrity and leak testing of aboveground piping and valves is unrealistic and could exacerbate the probability of or initiate system failures. The requirement should read “*visually inspect valves and aboveground piping periodically and conduct an engineering evaluation of unprotected underground piping once every five years.*” (67, 101, 128, 167,175; 1146 (1993 commenter)). We should require periodic visual examinations similar to the examinations proposed under §112.9(e). (101)

Internal and external inspection. We should clarify whether a visual inspection must be both internal and external. (76)

Supplement to inspections. An owner or operator should supplement integrity testing with visual inspections (95, 102) and recordkeeping (128). We should supplement visual inspections of aboveground valves and piping with a five-year integrity testing schedule. (175)

Response: *Support for proposal.* We appreciate commenter support.

Applicability. Integrity testing is essential for all aboveground containers to help prevent discharges. Testing will show whether corrosion has reached a point where repairs or replacement of the container is needed. Therefore, it must apply to large and small containers, containers on and off the ground wherever located, and to containers storing any type of oil. From all of these containers there exists the possibility of discharge. We agree that integrity testing of aboveground piping should be discretionary when the facility has secondary containment which would contain a discharge from such piping. Integrity and leak testing requirements are also applicable for containers and valves and piping that are entirely within buildings, or within mines, because in either case, such containers, or valves and piping may become the source of a discharge as described in §112.1(b). We have revised the rule to reflect that the requirement applies only to onshore and offshore bulk storage facilities. Therefore, a facility with only oil-filled

electrical, operating, or manufacturing equipment need not conduct such testing. We disagree that testing of valves, gathering lines, and flowlines would be prohibitively costly. In 1991, we estimated tank integrity testing and leak testing costs of buried piping. We estimated the costs as \$465 per tank, \$155 for equipment, and \$310 for installation. Small facilities were assumed to have no buried piping. Medium sized facilities were assumed to bear first year costs for tank installation and testing of \$4,704 and subsequent year costs of \$1,449. Large facilities were assumed to incur a first year cost of \$11,313, and subsequent year costs of \$3,519. We believe that this provision represents a negligible additional burden because most facilities are already testing such valves and gathering lines according to industry standards as a matter of good engineering practice. We believe that if such testing is done in accordance with industry standards, costs will be minimized because such standards will likely include options appropriate to the equipment tested at a reasonable cost.

We decline to exclude from §112.7(d) all tanks that are less than 15 years old, since the corrosion and discharge rates of one container will differ from the next. We also decline to require integrity testing only when the owner or operator determines that there is a risk of discharge, since that standard is not objective. We also disagree that we should only require owners or operators to integrity test valves and piping when corrosion or leakage has occurred or is potentially severe because it is inappropriate to require a test only when the system or equipment shows signs of potential failure. The idea of testing is to prevent such corrosion or leakage. Likewise, a weekly inspection for leaks is not the equivalent of conducting integrity tests. Visual inspection must be combined with some other technique.

Electrical equipment. Because electrical, operating, manufacturing equipment are not bulk storage containers, the requirement is inapplicable to those devices or equipment. 56 FR 54623. Also, as noted by commenters, methods may not exist for integrity testing of such devices or equipment.

Fixed aboveground piping. Section 112.7(d) applies both to completely buried and aboveground tanks, valves, and piping, including gathering lines and flowlines. There is no conflict with either §112.8(c)(4) or (d)(4). Section 112.8(c)(4) provides for “regular” testing of completely buried tanks. Section 112.8(d)(4) provides for “regular” inspection of aboveground valves, piping, and appurtenances, and integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement. Section 112.7(d) provides for “periodic” integrity testing, and “periodic” integrity and leak testing. Either “periodic” or “regular” testing should be conducted according to industry standards. Thus, there is no conflict between the rule provisions.

Impracticality. Integrity testing under §112.7(d) must be performed if the facility lacks secondary containment. You have discretion as to the method of testing, but it must be performed if it is possible to do so. If it is impossible, then the owner or operator must explain his reasons for nonconformance with the

requirement, and provide equivalent environmental protection by some other means.

Phase-in. We disagree that there should be a phase-in period. We believe that the time allowed in §112.3 for Plan amendment and implementation allows ample time for both existing and future facilities to comply with the changes in the rule.

Underground cable systems. Because electrical, operating, manufacturing equipment are not bulk storage containers, the requirement is inapplicable to those devices or equipment. 56 FR 54623. Also, as noted by commenters, methods may not exist for integrity testing of such devices or equipment.

Unprotected underground piping. We do not require periodic integrity testing for underground piping, since uncovering buried piping may present an undue hazard. Integrity and leak testing must be conducted when buried piping is installed, modified, constructed, relocated, or replaced. For comments on integrity testing requirements for cathodically protected piping and unprotected underground piping, see the comments on §112.8(c)(4) and (d)(1) in today's preamble.

Costs. We disagree that integrity testing is too costly because industry standards will likely incorporate options appropriate to the equipment at reasonable cost. It may help save the owner or operator money by preventing a discharge as described in §112.1(b).

In 1991, we estimated tank integrity testing and leak testing costs of buried piping. We estimated the costs as \$465 per tank, equipment of \$155, and installation costs of \$310 per tank. Small facilities were assumed to have no buried piping. Medium sized facilities were assumed to bear first year costs for tank installation and testing of \$4,704 and subsequent year costs of \$1,449. Large facilities were assumed to incur a first year cost of \$11,313, and subsequent year costs of \$3,519. We assume that this provision represents a negligible additional burden because most facilities are already testing such valves and gathering lines according to industry standards as a matter of good engineering practice.

Frequency of testing. We have modified our proposal in response to comments. We require such testing on a periodic basis instead of at a prescribed frequency, both for containers and for valves and piping. "Periodic" testing means testing according to a regular schedule consistent with accepted industry standards. We believe that use of industry standards, which change over time, will prove more feasible than providing a specific and unchanging regulatory requirement. As required by §112.8(c)(6), integrity testing of containers must be accomplished by a combination of visual testing and some other technique.

We disagree that required integrity testing may force an owner or operator to shut down the facility or its systems. Because such testing is performed on a periodic or scheduled basis, the owner or operator has discretion as to the schedule to keep the facility open as much as possible.

Integrity and leak testing. In response to a commenter who asked for a clarification of integrity testing, “integrity testing” is any means to measure the strength (structural soundness) of the container shell, bottom, and/or floor to contain oil and may include leak testing to determine whether the container will discharge oil. Facility components that might cause a discharge as described in §112.1(b) include containers, piping, valves, or other equipment or devices. Integrity testing includes, but is not limited to, testing foundations and supports of containers. Its scope includes both the inside and outside of the container. It also includes frequent observation of the outside of the container for signs of deterioration, leaks, or accumulation of oil inside diked areas. Such testing is also applicable to valves and piping. See API Standard 653 for further information on this term.

Leak testing for purposes of the rule is testing to determine the liquid tightness of valves and piping and whether they may discharge oil. Facilities that store oil, whether they are mines or other businesses, are required to employ integrity testing for their bulk storage containers, and integrity and leak testing for their valves and piping, to help prevent discharges. Containers that do not store oil, but merely use oil, are not subject to the requirement.

Methods of testing. We do not prescribe the method of testing, except to require that visual inspection must be combined with some other technique. We agree that an owner or operator may supplement hydrostatic testing with other inspection techniques while the tanks are in service and not being tested.

We disagree that visual inspection and nondestructive shell thickness testing are insufficient. Such testing should give the owner or operator an indication of the container’s integrity.

We disagree that an “engineering evaluation” of unprotected, underground piping is acceptable in lieu of an integrity and leak test because such evaluation may not provide equivalent environmental protection as integrity and leak testing of valves and piping. Likewise, a “routine inspection” of flowlines does not rise to the level of integrity and leak testing.

We disagree that integrity testing would require an owner or operator to completely drain and clean high pour point bulk storage containers. Testing may be possible without such drainage, either by using a particular method, for example, a robot, or performing such testing during regularly scheduled maintenance.

We also disagree that integrity testing will exacerbate the probability of system failures or negatively impact the environment. Integrity testing is a non-destructive type of testing that should not affect system failures. Its only effect on the environment should be a positive one, to help prevent a discharge as described in §112.1(b).

An owner or operator must consider the tank design and its construction material when determining an appropriate testing schedule and method, and may determine a *periodic*

testing schedule and method based on good engineering practice, relevant industry standards, and optimal use of facility resources. The owner or operator must also consider factors such as the potential for tank failure, tank design, and tank material when determining an appropriate testing schedule and method. Among these factors should be how the material stored affects the structural integrity of the tank. We disagree with the commenter who stated that integrity testing is necessary only after material repairs. A discharge may occur at any time, regardless of whether an owner or operator has conducted repairs.

Guidance. Due to rapidly changing technology, we cannot list all types of integrity testing methods. There is no single operational standard we can prescribe for all non-transportation-related facilities. However, we include industry standards in the preamble to today's final rule to assist the reader. See the discussion in §§112.7(d) and 112.8(c)(6). We also list organizations that help to formulate industry standards in section IV.D of today's preamble.

Pressure testing. We do not require pressure testing. Therefore, none of the problems cited with such testing are relevant.

Reference to §112.7(c). The reference in proposed §112.7(d) was to proposed §112.7(c). Section §112.7(d) integrity testing and integrity and leak testing requirements apply to any facility which lacks secondary containment.

Visual inspection. The rule requires visual testing in conjunction with another method of testing, because visual testing alone is normally insufficient to measure the integrity of a container. Visual testing alone might not detect problems which could lead to container failure. For example, studies of the 1988 Ashland oil spill suggest that the tank collapse resulted from a brittle fracture in the shell of the tank. Adequate fracture toughness of the base metal of existing tanks is an important consideration in discharge prevention, especially in cold weather. Although no definitive non-destructive test exists for testing fracture toughness, had the tank been evaluated for brittle fracture, for example under API standard 653, and had the evaluation shown that the tank was at risk for brittle fracture, the owner or operator could have taken measures to repair or modify the tank's operation to prevent failure.

For certain smaller shop-built containers in which internal corrosion poses minimal risk of failure; which are inspected at least monthly; and, for which all sides are visible (i.e., the container has no contact with the ground), visual inspection alone might suffice, subject to good engineering practice. In such case the owner or operator must explain in the Plan why visual integrity testing alone is sufficient, and provide equivalent environmental protection. 40 CFR 112.7(a)(2). However, containers which are in contact with the ground must be evaluated for integrity in accordance with industry standards and good engineering practice.

X - G: Inspections, tests, and records - §112.7(e)

Background: Under §112.7(e)(8) of the current rule, an owner or operator must maintain inspection records as part of an SPCC Plan for three years. In §112.7(e) of the 1991 proposed rule, we proposed to extend the period for retaining records of inspections, test results, and written procedures from three to five years. We proposed this extension to be consistent with the Federal statute of limitations on assessing civil penalties for violating the SPCC rule. We also proposed that these records be maintained with an SPCC Plan, and not as part of an SPCC Plan. In 1997, we proposed to retain the three-year record retention standard.

Comments: *Editorial suggestion.* In the first sentence of §112.7(e), we should change the word *shall* to *must*. (121)

Form of records. "...written procedures for testing only should be omitted from the proposed rule." Believes that "written procedures for testing can be quite lengthy and would have meaning to the tester only." (37) 40 CFR part 112 should include the testing required by 40 CFR part 280. (47)

Date. Each inspection and test report should be dated. (47)

Electronic format. "Using electronic media for the storage and retrieval of standard operating practices, inspection protocols, testing procedures, and maintenance records is becoming commonplace in industry. BP requests that language be inserted in this section to allow the use of computers or other electronic devices for the purpose of satisfying this section." (96)

Repairs and training. In §112.7(e), we should require owners or operators to keep records and tests of all major repairs and of employee training, in addition to written procedures and records of inspections and tests. (147)

Maintenance with Plan.

Accessible location. "FINA proposes that the records be maintained at the facility or at an alternate location accessible within 24 hours." (25, 37, 38, 47, 67, 83, 187)

Principal place of business. Owners or operators should maintain records for the most current three years with the Plan, and should maintain records for the remaining two years at the facility's principal place of business. (54)

Required inspections and tests. "It would be helpful if EPA could include a list of all inspections and tests required by this part." (16)

Time period.

Opposes 5-year proposal. (22, 33, 67, 101, 113, 167, 181, 187) An obligation to maintain records for five years places an undue administrative burden on facility

owners or operators. (45, 113, 181) A five-year record retention provision is inconsistent with other environmental protection regulations. (See, for example, Resource Conservation and Recovery Act regulations, 40 CFR parts 264 and 265, and Department of Transportation requirements.) (35, 78, 109, 153) We should require owners or operators to retain records in accordance with other State and Federal agency requirements to avoid additional and unnecessary costs. (114)

2 years. We should reduce the record retention period to two years. (45)

Phase-in. “API suggests that in order to be consistent with record retention requirements under the NPDES program of the CWA, records should only be retained for three years. However, if the Agency insists on a new five year requirement, because the required records have only been maintained for three years consistent with the current regulation, there will be a need for at least a phase-in period to bring those records which were retained into compliance with this new provision.” (67, 79, 95, 101, 102)

3 years. Retaining records for three years should be adequate, since we require the review and recertification of an SPCC Plan every three years. (66)

Small facilities.

Opposes requirement. The proposed requirement to maintain records with the SPCC Plan for five years would be particularly burdensome for small facilities. (28, 58, 62, 101) Proposed §112.7(e) is only appropriate for large facilities. (192)

Favors requirement. Maintaining records with the Plan should only apply to small facilities. (9,77)

Response: *Editorial suggestion.* In response to the comment that we change *shall* to *must* in §112.7(e), we agree, and have made that change throughout the rule to further our plain language objectives.

Form of records. Records of inspections and tests required by this rule may be maintained in electronic or any other format which is readily accessible to the facility and to EPA personnel. Whatever format you use, however, must be readily accessible to response personnel in an emergency. If such records are produced in a medium that is not readily accessible in an emergency, they must also be available in a medium that is.

For example, records might be electronically produced, but computers fail and may not be operable in an emergency. For electronic records, or records produced in another medium, therefore, backup copies must be readily available on paper. At least one version of the records should be written in English so that they will be readily understood by an EPA inspector.

Usual and customary business records may be those ordinarily used in the industry, including those made under API standards, Underwriters’ Laboratories standards,

NPDES permits, a facility's Q.S.-9000 or ISO-14000 system, or any other format acceptable to the Regional Administrator. If you choose to use records associated with compliance with industry standards, such as Underwriters' Laboratories standards, you must closely review the inspection, testing, and record keeping requirements of this rule to ensure that any records kept in accordance with industry standards meets the intent of the rule. Some standards have limited record keeping requirements and may only address a particular aspect of container fabrication, installation, inspection, and operation and maintenance. The intent of the rule is that you will not have to maintain duplicate sets of records when one set has already been prepared under industry or regulatory purposes that also fully suffices for SPCC purposes. The use of these alternative record formats is optional; you are not required to use them, but you may use them.

We disagree that we should omit written procedures for testing. Such procedures are essential for implementation of testing and inspection requirements, and must be described in the Plan. We disagree that we should include the testing requirements of 40 CFR part 280 in the rule, however, such procedures may be applicable, subject to good engineering practice.

Date. Dated records are essential to document compliance with both substantive and recordkeeping requirements. Dated records are also consistent with usual and customary business practices.

Maintenance with Plan. We agree with commenters that it is not necessary to maintain records as part of the Plan. Therefore, today's rule allows "keeping" of the records "with" the Plan, but not as part of it. In the current rule, such records "should be made part of the SPCC Plan..." 40 CFR 112.7(e)(8). Because you continually update these records, this change will eliminate the need to amend your Plan each time you remove old records and add new ones. You still retain the option of making these records a part of the Plan if you choose.

Records required. The rule permits use of usual and customary business records, and covers all of the inspections and tests required by this part as well as any ancillary records. "Inspections and tests" include not only inspections and tests, but schedules, evaluations, examinations, descriptions, and similar activities required by this part.

Required inspections and tests. After publication of this rule, we will list all of the inspections and tests required by part 112 on our website (www.epa.gov/oilspill). The applicability of each inspection and test will depend on the exercise of good engineering practice, because not every one will be applicable to every facility.

Time period. We agree with commenters that maintenance of records for three years is sufficient for SPCC purposes, since that period will allow for meaningful comparisons of inspections and tests taken. Therefore, there will also be no new costs. We note, however, that certain industry standards, for example API Standards 570 and 653, may specify record maintenance for more than three years.

We disagree that we should require record retention in accordance with State and other Federal requirements. State and Federal record retention requirements vary, making it difficult to establish a single standard.

X - H: Training - §112.7(f)

Background: Section 112.7(e)(10) in the current rule prescribes the employee training requirements and discharge prevention procedures that a facility owner or operator must observe. It provides that owners or operators are responsible for properly instructing personnel, and scheduling and conducting spill prevention briefings at intervals frequent enough to assure adequate understanding of the SPCC Plan. In 1991, we redesignated §112.7(e)(10) as §112.7(f), and proposed to require: (1) an owner or operator to conduct training exercises at least annually for all personnel, and train new employees within their first week of work; and, (2) an owner or operator to schedule and conduct spill prevention briefings at least once a year. We also proposed specific training subjects for inclusion in the training program.

Comments: *Support for proposal.* “Shell agrees with this proposal and has been conducting such retaining at their facilities.” (10, 27, 96, 143, 147, 185)
Applicability.

Bulk storage. We should require staff training for major bulk terminal and tank farm facilities. (192)

Existing programs. Facilities should be allowed to incorporate SPCC training provisions into already existing training programs required by other Federal or State regulations. (91, 96, 162)

Operation and maintenance of equipment. “The rule should only apply to ‘personnel involved in oil transfer operations, emergency response, and countermeasure activities.’ It should not apply to clerks, secretaries, and like employees. (14, 35, 42, 45, 48, 57, 62, 66, 67, 71, 77, 88, 92, 98, 103, 115, 117, 125, 141, 164, 167, 173, 175, 180, 181, 182, 187, 189, L7, L12, L18, L24)

Small facilities. We should provide for a small facility exemption. (79, 109, 175, 180, 182)

Content of training. Training should address the initial response to a spill, such as emergency notification and implementation of emergency containment measures. Exercises of these emergency plans should be conducted at least annually. (1) Objects to the proposal that employees be trained in maintenance of oil storage equipment or oil transfer procedures. (42, 125)

Discharge prevention briefings. “API suggests that section 112.7(f)(3) be amended to require ‘briefings for operating personnel at least once a year ... to assure understanding

of the SPCC plan for that facility in conjunction with the annual training.’ This paragraph should also require briefings of ‘new operational employees during their indoctrination with their job responsibilities, and as appropriate for all affected operational personnel when changes are made to the existing Plan necessitating recertification.” (67) Favors the present requirement to hold spill prevention briefings “at intervals frequent enough to assure adequate understanding of the SPCC Plan.” (78)

Documentation. The rule should include a provision that owners or operators document each training session and spill response drill conducted, and maintain training session and drill records for five years. (47, 96)

Editorial suggestion. We should clarify proposed §112.7(f), in which we continue to use the word *should*. The commenter suggested that we replace *should* with either *shall* or “it is recommended” to avoid confusion. (16)

Timing of employee training.

Support for annual training requirement. We should allow owners or operators to coordinate SPCC Plan training with local oil spill response organizations or Local Emergency Planning Committees (LEPCs) whenever possible. (27) Favors proposed provision for annual training exercises. (27, 34, 141)

Opposition to prescribed training periods. We should avoid requiring a period for conducting training exercises. (62, 66, 71, 109, 113, 128)

Drills. The annual training should not be considered a full-scale SPCC drill. (L3)

New employees. We should define the phrase *new employee*. (103) Others oppose the provision to train new employees within one week of employment, arguing that such a provision is impractical, and called for employer discretion in scheduling training. Some suggested varying time periods in lieu of one week. Those suggestions ranged from one month to one year, with alternatives suggested such as “as soon as practical,” “prior to operation but before one year,” “within one week of job assignment,” “a more reasonable time period,” “after training,” and “until the next annual training for all employees.” (5, 28, 31, 34, 35, 36, 38, 55, 57, 62, 66, 67, 70, 71, 77, 79, 87, 89, 90, 92, 93, 96, 98, 101, 103, 113, 114, 115, 117, 118, 125, 128, 133, 141, 145, 155, 158, 162, 164, 173, 182, 187, 189, L6, L7, L14, L29)

Response: *Support for proposal.* We appreciate commenter support.

Applicability. We believe that training requirements should apply to all facilities, large or small, including all those that store or use oil, regardless of the amount of oil transferred in any particular time. Training may help avert human error, which is a principal cause of oil discharges. “Spills from ASTs may occur as a result of operator error, for example, during loading operations (e.g., vessel or tank truck - AST transfer operation), or as a result of structural failure (e.g., brittle fracture) because of inadequate maintenance of

the AST.” EPA Liner Study at 14. The 1995 SPCC Survey found that operator error was the most common spill cause for facilities in 9 of the 19 industry categories that reported having spills. Also, the August 1994 draft report of the Aboveground Oil Storage Facilities Workgroup called “Soil and Ground Water Contamination from Aboveground Oil Storage Facilities: A Strategic Study” presented data on causes of discharges from two studies. Both studies showed that error during product transfer activities is one of the biggest known causes of discharges at AST facilities. Two other studies also support our contention: Carter, W.J., “How API Viewed the Needs for Aboveground Storage Tanks,” Tank Talk, Vol. 7, July/August 1992, p.2.; and U.S. EPA, “The Technical Background Document to Support the Implementation of OPA Response Plan Requirements,” Emergency Response Division, Office of Solid Waste and Emergency Response, February 1993, p.4-19. We have therefore retained the applicability of training to all facilities. The 1993 proposal would have limited training requirements to only certain facilities which received or transferred over the proposed amount of oil. Facilities which receive or transfer less than the proposed amount might also have discharges which could have been averted through required training. Also the proposed rule would have exempted many facilities that use rather than store oil from its scope. Therefore, we have provided in the rule that all facilities, whether bulk storage facilities or facilities that merely use oil, must train oil-handling employees because all facilities have the potential for a discharge as described in §112.1(b), and training is necessary to avert such a discharge.

We agree with the commenter that training is only necessary for personnel who will use it to carry out the requirements of this rule. Therefore revised paragraph (f)(1) provides that only oil-handling personnel are subject to training requirements, as we proposed in 1993. “Oil-handling personnel” is to be interpreted according to industry standards, but includes employees engaged in the operation and maintenance of oil storage containers or the operation of equipment related to storage containers and emergency response personnel. We do not interpret the term to include secretaries, clerks, and other personnel who are never involved in operation or maintenance activities related to oil storage or equipment, oil transfer operations, emergency response, countermeasure functions, or similar activities.

Existing programs. You may incorporate SPCC training requirements into already existing training programs required by other Federal or State law at your option or may conduct SPCC training separately. You may coordinate such training with training on other subjects, or with other agencies like LEPCs or oil spill response organizations.

Content of training. Specifying a minimum list of training subjects is necessary to ensure that facility employees are aware of discharge prevention procedures and regulations. As suggested by a commenter, we have added knowledge of discharge procedure protocols to the list of training subjects because such training will help avert discharges. Therefore, we have specified that training must include, at a minimum: the operation and maintenance of equipment to prevent the discharge of oil; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility

operations; and, the contents of the facility Plan. As noted above, we require response training for facilities that must submit response plans, but such training is not necessary for all SPCC facilities.

In response to the utility commenter who asserted that utility employees do not need to be trained in the maintenance of oil storage tanks because such maintenance does not involve the transfer and handling of oil, we note that training must address relevant maintenance activities at the facility. If there is no transfer and handling of oil, such topic need not be covered in training.

Discharge prevention briefings. Annual discharge prevention briefings are necessary, but there should be more frequent briefings where appropriate. Such briefings are necessary to refresh employees' memories on facility Plan provisions and to update employees on the latest prevention and response techniques. Training must include the contents of the facility Plan. Although it is desirable, we disagree that we should require SPCC briefings to include emergency response training. That training is already required for those facilities which must prepare response plans.

Documentation. You must document that you have conducted required training courses. Such documentation must be maintained with the Plan for three years.

Editorial suggestion. We agree with the commenter, and have made the editorial change from "should" to "must" for all requirements. We have eliminated all recommendations from the rule to avoid confusing the regulated public with what is mandatory and what is discretionary. Therefore, no *shoulds* remain in the rule.

Timing of employee training. We agree with commenters who thought it desirable to leave the timing and number of hours of training of oil-handling employees, including new employees, to the employer's discretion. "Proper instruction" of oil-handling employees, as required in the rule, means in accordance with industry standards or at a frequency sufficient to prevent a discharge as described in §112.1(b). This standard will allow facilities more flexibility to develop training programs better suited to the particular facility. While the rule requires annual discharge prevention briefings, we also agree that the annual briefings required are not drills. In any case, the SPCC rules do not require drills, as explained below.

For purposes of the rule, it is not necessary to define a "new employee" because all oil-handling personnel are subject to training requirements, whether new or not. You do, however, have discretion as to the timing of that training, so long as the timing meets the requirements of good engineering practice.

Unannounced drills. The proposed yearly frequency for unannounced drills is also unnecessary because such drills are already required at FRP facilities, which are higher risk facilities. We do not believe that the risk at all SPCC facilities approaches the same level as at FRP facilities. Therefore, we are not finalizing this proposal, and there are no new costs.

X - I: Security (excluding oil production facilities) - §112.7(g)

Background: Since vandalism is a factor in many spills, we proposed in 1991, to modify the provisions for adequate and effective security. We also proposed to redesignate §112.7(e)(9) as §112.7(g). These provisions would prevent facility access by unauthorized persons and prevent tampering with equipment and tanks. We proposed in §112.7(g)(1) to recommend - not require - that owners or operators fully fence all plants handling, processing, or storing oil, and ensure that gates are locked or guarded when the facility is not in production or is unattended.

In §112.7(g)(2), we proposed to clarify that under current §112.7(e)(9)(ii), an owner or operator must have adequate security to ensure that valves remain *in the closed position* when in non-operating or non-standby status. These valves include master flow and drain valves and any other valves that permit direct outward flow of the tank's contents to the surface. This proposal would allow owners or operators more flexibility in choosing a method of securing the valves, because the current rule requires the valves to be locked.

We proposed editorial changes in redesignated §112.7(g)(3) (currently §112.7(e)(9)(iii)) to require that an owner or operator lock the starter control on all pumps in the "off" position. When the pumps are in a non-operating or non-standby status, the owner or operator would have to locate the starter control at a site accessible only to authorized personnel.

Proposed §112.7(g)(4) (currently §112.7(e)(9)(iv)) would require an owner or operator to ensure that oil pipeline loading and unloading connections are securely capped or blank-flanged when not in service or standby service for an extended time. We proposed to clarify that "an extended time" is six months or more.

We proposed to recommend in redesignated §112.7(g)(5) (currently §112.7(e)(9)(v)) that facility lighting be commensurate with the facility type and location.

Comments: *Support for proposal.* Favors recommendations for establishing security at a facility. (143)

Opposition to proposal. We should tailor security requirements to specific facility needs. The PE and any responsible company official should determine the security requirements. (162)

Applicability.

Mobile facilities. "Mobile facilities should be exempt from the requirements as well. When in operation they are manned 24 hours per day. In addition, the physical requirements such as landing, loading and unloading connections are not applicable to a mobile facility." (128)

Editorial suggestion. We should define the term "plant." Security options often are limited for facilities located in residential areas. (37)

Fences.

Recommendation. We should recommend that owners or operators fully fence plants with a chain link fence with barbed wire - an adequate system for deterring vandalism. (16) Supports §112.7(g)(1) *recommendation* to fence a facility, since owners or operators need discretion not to fence where it is impracticable or undesirable. (57)

Requirement. We should change the proposed §112.7(g)(1) recommendation to a requirement or delete it. (121)

Loading/unloading connections. "Larger facilities often have seasonal or contractual variations in the use of lines, pumps, racks and connections. Therefore, it would be costly and impractical to blank off lines only to reopen them in the seventh month. At such facilities, an unused tank would be closed but the piping would remain open. Accordingly, the regulation should recognize normal operating procedures at some facilities and provide operating flexibility while maintaining the necessary security." (54) We should specify that "securely capped" connections include quick-disconnect fittings. (92) We should clarify that the second sentence in §112.7(g)(4) regarding the loading and unloading connection provision included piping emptied of liquid content either by draining or by inert gas pressure. (121) Supports proposal that "an extended time" means more than six months. (147)

Starter controls on pumps. "IFTOA recommends that EPA modify the requirement so that it would apply to facilities, not pumps, that have been closed for six months or more and the rule should be amended to read 'locked in the 'off' position or electronically disconnected.' Disconnection, of course, serves the same purpose and frequently is much easier to control." (54) "There is no need for the double security being proposed with the word 'and' instead of 'or' in the aforementioned requirement. Such double security offers no additional benefit to deter vandals or other unauthorized persons." (67, 79, 85, 95, 102) "At a large facility, such a security requirement becomes unwieldy. The potential for losing keys or having the locks become inoperative due to freezing conditions is great." (88) We should state that pumps *must be* locked in the "off" position. (121)

Response: *Support for proposal.* We appreciate commenter support.

Applicability of requirements. We asked in the 1991 preamble (at 56 FR 54616) for comments as to whether provisions proposed as discretionary measures or recommendations should be made requirements. We were concerned whether these proposed measures represented good engineering practice for all facilities. Specific comments are discussed below. In the case of proposed §112.7(g)(1) and (5) as requirements, we have decided to retain the requirements as requirements rather than convert those paragraphs into recommendations as proposed. We have done this

because we believe that fencing, facility lighting, and the other measures prescribed in the rule to prevent vandalism are elements of good engineering practice in most facilities, including mobile facilities. Where they are not a part of good engineering practice, we have amended the proposed provision allowing deviations, §112.7(a)(2), to include the provisions in §112.7(g).

Editorial suggestion. We agree that the term “plant” has no clear meaning. Therefore, in paragraph (g)(1), we have substituted the term “facility” in its place, which is a defined term in these rules.

Fences. Fencing helps to deter vandals and thus prevent the discharges that they might cause. In response to the commenter who argued that fences should be topped with barbed wire, or otherwise designed to deter vandalism, we agree. When you use a fence to protect a facility, the design of the fence should deter vandalism. Methods of deterring vandals might include barbed wire or other devices. If any type of fence is impractical, you may, under §112.7(a)(2), explain your reasons for nonconformance and provide equivalent environmental protection by some other means.

Loading/unloading connections. In response to comment, we have decided to retain the current time line in §112.7(g)(4), i.e., “an extended time,” instead of specifying a six-month time line, due to the need for operational flexibility at facilities. We define “an extended time” in reference to industry standards or, in the absence of such standards, at a frequency sufficient to prevent any discharge. The appropriate method of securing or blank flanging of these connections is a matter of good engineering practice, and might include “quick disconnect fittings” as a possible deviation under §112.7(a)(2). In any case, a secure cap is one equipped with some kind of lock or secure closure device to prevent vandalism. We disagree that the requirements of this paragraph should apply to the owner or operator of a facility instead of the owner or operator of the piping because a facility might place only some piping out of service for a period of time, and let other piping remain in service. Therefore, the owners or operators of some piping might escape the requirements of the rule and be more likely to discharge oil.

We disagree that this requirement is costly or impractical. The requirement may save money by preventing costly discharges and cleanups.

Regarding making the §112.7(g)(4) requirements apply to facilities (not piping), we decline to make this change because facilities in service often place some, but not all, of the piping out-of-service for some period. The current requirement covers *any* piping out-of-service for an extended time, regardless of whether the facility is in service.

In response to comment, we note that paragraph (g)(4) applies to piping emptied of liquid content either by draining or by inert gas pressure.

Starter controls on pumps. We disagree that the requirements to have the starter control locked in the off position and be accessible only to authorized personnel are redundant. Restricting access to such pumps prevents unauthorized personnel from accidentally

opening the starter control. These measures are necessary to prevent discharges at small as well as large facilities because the threat of discharge is the same regardless of the size of the container, and a small discharge may be harmful to the environment. If the potential for losing keys, weather conditions such as frequent freezing, or other engineering factors render such a measure infeasible, you may use the deviation provisions in §112.7(a)(2) if you can explain your reasons for nonconformance and provide equivalent environmental protection by some other means.

A facility may have some, but not all, pumps out-of-service for various periods - even during facility operations. We decline to exempt pumps which are out-of-service for six months or more because it would reduce the effectiveness of this preventive measure by leaving some piping unprotected for up to half a year.

Valves. Revised §112.7(g)(2) requires you to ensure that the master flow and drain valves and other valves permitting outward flow of the container's contents have adequate security measures. The current rule requires that such valves be securely locked in the closed position when in non-operating or non-standby status. Today's revised rule allows security measures other than locking drain valves or other valves permitting outflow to the surface. Manual locks may be preferable for valves that are not electronically or automatically controlled. Such locks may be the only practical way to ensure that valves stay in the closed position. For electronically controlled or automated systems, no manual lock may be necessary. The rule gives you discretion in the method of securing valves. We believe that this flexibility is necessary due to changes in technology and in the use of manual and electronic valving.

X - J: Facility tank car and tank truck loading/unloading racks - §112.7(h)

Background: Section 112.7(e)(4) of the current rule describes the precautionary measures an owner or operator must undertake in tank car and tank truck loading/unloading racks to prevent discharges during transfers. Section §112.7(e)(4)(i) requires that tank car and tank truck loading and unloading procedures meet the Department of Transportation's (DOT) minimum requirements and regulations. Section 112.7(e)(4)(ii) requires that, where rack area drainage does not flow into a catchment basin or treatment facility designed to handle spills, an owner or operator must use a quick drainage system. Further, the containment system must be able to hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the plant. Under §112.7(e)(4)(iii), an owner or operator must use an interlocked warning light, physical barrier system, or warning signs in loading/unloading areas to prevent vehicular departure before complete disconnect. Section 112.7(e)(4)(iv) of the current rule describes the examination and maintenance requirements that must be completed prior to filling and departure.

In 1991, we repropose current §112.7(e)(4), with a few changes. In §112.7(h)(1), we proposed language requiring that tank truck loading/unloading procedures meet the minimum requirements and regulations established by State and Federal law, in place of

the current requirement that these procedures comply with DOT requirements and regulations.

Comments: *Alarm or warning systems.* EPA should consider “adding the additional requirement that wheel chocks be used during all tank truck transfers “to guarantee that tank trucks will not roll unexpectedly while the loading arm is attached and the driver is out of the cab.” (16) We should revise §112.7(h)(3) to include additional industry standard equipment, and read as follows: “(3) An interlocked warning light or physical barrier system, vehicle brake interlock system, or warning signs, or a system substantially similar in effectiveness shall be provided . . .” (83)

Applicability. Asks us to clarify which types of facilities are subject to these provisions. (79) Asks whether this section applies only to facilities “routinely used for loading or unloading of tanker trucks from or into aboveground bulk storage tanks” or to any loading or unloading operation. (125)

Phase-in. We should allow facility owners or operators at least two years to comply with the requirements of this section. (71) We should provide more than 60 days from the date we promulgate the final rule. (125)

Production facilities. “We believe that EPA should clarify that the provisions of this section do not apply to crude oil transfers from production fields into tank trucks. Adequate protection from the small drips that may occur from transferring crude to a tank truck is provided by a small sump or catchment basin.” (75, 145, 167)

Small facilities. We should exempt small oil production facilities. (28, 79, 175) We should exempt small aboveground tanks containing 1,000 barrels or less of oil. A portable drip pan has been sufficient for the degree of spill risk at such facilities. (67, 91, 101) Onshore production facilities should be exempted because they are small and have a negligible spill history. (167)

Warning system. Asks whether the interlocking warning system requirement applies to tank batteries, plants, or both. (28, 101)

Cost. Most Appalachian oil production operations would have to newly install the secondary containment system required under this section. Asks whether we factored the economic impact of installing such containment into the fiscal impact of the proposed rule. (28, 31, 113, 165, 187, L15)

Editorial suggestions. We should replace *loading/unloading rack* with *loading/unloading area* in the section title to clarify that the provisions apply to all types of loading/unloading stations. (47) We should define *facility tank car and tank truck loading/unloading racks* to clarify the type of facility to which this provision applies. (58, 79) We should move all of §112.7(h) to §112.8. (121)

Other State or Federal law. “While SPCC facilities are subject to such requirements in addition to the SPCC rules, failure to meet such other requirements should not constitute a violation of the SPCC rules.” (67) We should remove the reference to other state and federal law from the rule. (121) “The Company feels that proposed §112.7(h) should be eliminated. ... These are Department of Transportation items and should be covered by that Department’s rules governing loading, unloading, and vehicle inspection. The compliance onus should be on the transporter.” (164)

Secondary containment.

Support. Some degree of secondary containment is necessary during truck loading, but questions the need for such a large catchment system. (187)

Contingency plan instead. We should allow a strong contingency plan in place of secondary containment. (28, 31, 101, 165, L15)

Methods. We should clarify whether the use of any of the discharge prevention systems in §112.7(c) would satisfy §112.7(h)(1) that the containment system be designed “to hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded in the plant.” (115)

Quick drainage system. We should define the term *quick drainage system*. Asks whether there are other acceptable ways to comply with this regulation (e.g., blocking nearby storm drains). (29) Recommends that we allow owners or operators to use the drainage control structures/equipment listed in §112.7(c) in place of the quick drainage system. (124)

Completely buried tanks. “The Ohio Utilities request U.S. EPA interpretation on whether such requirement applies solely to aboveground tank loading and unloading areas, or whether it would also apply to underground storage tank loading and unloading areas as well. If this provision attempts to regulate underground storage tanks loading and unloading areas, the Ohio Utilities strongly believe that such attempted regulation is inappropriate and would result in a multiplicity of regulation since the federal underground storage tank regulations, 40 CFR part 280, already regulate, to some extent, the loading and unloading procedures of underground storage tanks.” (189)

Response personnel instead. “Because many tank car loading/unloading facilities are located on railroad property, or modifications that could undermine the railway bed are subject to railroad approval, providing containment for railcars is typically not feasible. ... Operators should have the option of providing for response personnel to be placed on alert when such an activity is to take place, and, where site conditions allow, provide a capture plan similar to, but more limited in scope, than a full contingency plan. This would encourage secondary containment for storage tanks and other potential sources.” (76)

Unnecessary, procedures instead. “GM believes that mandatory tank car loading and unloading containment systems designed to hold at least the maximum capacity of any single compartment of a tank car or tank truck is unnecessary and costly. The cost to renovate existing loading and unloading areas at large manufacturing facilities is substantial and may have negligible environmental benefit if a spill does not occur or if the spill is not the entire contents of the tanker. ... GM recommends that in lieu of mandatory containment of the entire contents of the largest compartment of the tanker, an owner be allowed to demonstrate that procedures are in place to ensure that personnel are present at all times to supervise tank truck loading and unloading.” (90)

Vehicle drain closure. “Accordingly, EPA should delete that portion of proposed section 112.7(h)(4) relating to examination and repair of trucks from the final rule. First, in most cases the trucks that pull up under a terminal’s rack do not belong to the owner or operator of the facility. They are the property of petroleum marketers who are independent from the facility owner or operator. ... Second, facility employees are not trained or capable of properly examining and repairing trucks to prevent leakage, and such an obligation certainly could result in a major safety problem. Third, many facilities are completely automated or automated during certain periods of time during the day or night; there is no one at the facility. Thus, the requirement would prevent the operation of terminals at these times and would substantially disrupt the petroleum distribution system nationwide. Fourth, the Department of Transportation imposes the responsibility for maintenance and repair of motor vehicles on the owner or operator of the vehicle, the individual who controls the vehicle. EPA should adopt the same policy.” (54, 115)

Response: *Alarm or warning systems.* The requirement to provide a warning light or other physical barrier system applies to the loading/unloading areas of facilities. We have amended the rule on the suggestion of a commenter to include “vehicle brake interlock system or other system substantially similar in effectiveness,” and “wheel chocks.” The examples listed in the rule of potential warning systems are merely illustrative. Any other alarm or warning system which serves the same purpose and performs effectively will also suffice to meet this requirement.

Applicability. This section is applicable to any non-transportation-related or terminal facility where oil is loaded or unloaded from or to a tank car or tank truck. It applies to containers which are aboveground (including partially buried tanks, bunkered tanks, or vaulted tanks) or completely buried (except those exempted by this rule), and to all facilities, large or small. All of these facilities have a risk of discharge from transfers. Our Survey of Oil Storage Facilities (published in July 1996) showed that as annual throughput increases, so does the propensity to discharge, the severity of the discharge, and, to a lesser extent, the costs of the cleanup. Throughput increases are often associated with transfers of oil.

The requirements contained in this section, including those for secondary containment, warning systems, and inspection of trucks or cars for discharges are necessary to help prevent discharges. If you can justify a deviation for secondary containment requirement

in paragraph (h)(1) on the basis that it is not practicable from an engineering standpoint, you must provide a contingency plan and take other actions to comply with §112.7(d). If you seek to deviate from any of the requirements in paragraphs (h)(2) or (3), you must explain your reasons for nonconformance, as provided in §112.7(a)(2), and provide measures affording equivalent environmental protection.

We disagree that a contingency plan (whether labeled “strong” or otherwise) is a preferable alternative to secondary containment. Secondary containment is preferable because it may prevent a discharge that may be harmful as described in §112.1(b). A contingency plan is a plan for action when such discharge has already occurred. However, as noted earlier, if secondary containment is not practicable, you must provide a contingency plan and take other actions as required by §112.7(d). EPA will continue to evaluate the issue of whether the provisions for secondary containment found in §112.7(h)(1) should be modified or revised. We intend to publish a notice asking for additional data and comment on this issue.

We disagree that the section regulates activities already under the purview of the U.S. Department of Transportation. We regulate the environmental aspects of loading/unloading transfers at non-transportation-related facilities, which are legitimately part of a prevention plan. DOT regulates other aspects of those transfers, such as safety measures.

Phase-in. None of the requirements of §112.7(h) are new, therefore compliance is already required, and no phase-in is necessary.

Cost. We believe that we have considered costs adequately, and invite the interested reader to review the Regulatory Analyses in the docket for this rulemaking. This is not a new requirement, and therefore, none of the costs are “new”. Appalachian and other oil production operators who are presently in compliance with these provisions will not incur additional economic impact as a result of the revision.

Editorial suggestion. We disagree that we should change *loading rack* to “loading/unloading area” because we did not propose the change. We disagree that we should move the requirements to §112.8. We intend §112.7(h) to apply to all facilities, including production facilities; §112.8 does not cover production facilities.

Other State or Federal law. We have withdrawn, as unnecessary, proposed §112.7(h)(1), which would have required that facilities meet the minimum requirements of Federal and State law. Those requirements apply whether they are mentioned or not.

Secondary containment. As noted above, the requirement for secondary containment applies to all facilities, whether with aboveground or completely buried containers. This includes production facilities and small facilities. The method of secondary containment must be one of those listed in the rule (see §112.7(c)), or some similar system that provides equivalent environmental protection. The choice of method is one of good engineering practice. However, in response to comments, we note that sumps and drip pans are a listed method of secondary containment for offshore facilities. A catchment

basin might be an acceptable form of retention pond for an onshore facility. Whatever method is implemented, it must be capable of containing the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded in the facility. A discharge from the maximum capacity of any single compartment of a tank car or tank truck includes a discharge from the tank car or tank truck piping and hoses. This is the largest amount likely to be discharged from the oil storage vehicle. A requirement that secondary containment be able to hold only five percent of a potential discharge when procedures are in place to prevent discharges fails to protect the environment if there is human error in one of those procedures. In case of discharge, the secondary containment system must be capable of preventing a discharge from that maximum capacity compartment to the environment. As mentioned above, if secondary containment is not practicable, you may be able to deviate from the requirement if you provide a contingency plan and otherwise comply with §112.7(d).

Regarding the presence of personnel (as supervisors) to substitute for secondary containment, we agree that spill prevention is always preferable to spill containment. However, preventive measures do not replace the need for a secondary containment system as these measures will never completely eliminate the potential for a spill to occur. Such measures, however, might be part of the contingency plan required when secondary containment is impracticable.

Quick drainage system. A quick drainage system is a device that drains oil away from the loading/unloading area to some means of secondary containment or returns the oil to the facility. We note that this provision does not apply to any UST system excluded from part 112 under §112.1(d)(4).

Vehicle drain closure. We believe that the requirement to check vehicles for discharge is important to help prevent discharges. If the check were not done, the entire contents of the vehicle might be discharged. We further believe that the responsibility for compliance with proposed §112.7(h)(3), as well as with all provisions of the rule, continues to rest with the owner or operator of the facility when those vehicles are loading or unloading oil at the facility. If personnel are not present to inspect the vehicles, the owner or operator must explain his reasons for nonconformance and provide equivalent environmental protection by some other means. See §112.7(a)(2).

X - K: State rules - §112.7(j)

Background: Section 112.7(e) of the current rule requires an owner or operator to discuss conformance with §112.7 or more stringent State rules, requirements, and guidelines. In §112.7(i) of the 1991 proposed rule (redesignated as §112.7(f) in the final rule), we repropose the requirement that in addition to the minimal prevention standards listed under §112.7(c), (e), (f), (g), and (h) the owner or operator include in an SPCC Plan a complete discussion of conformance with the applicable requirements and “other effective spill prevention and containment requirements listed in §§112.8, 112.9, 112.10, and 112.11 (or, if more stringent, with State rules, regulations, and guidelines).

Comments: *Editorial suggestion.* We should move §112.7(i) to §112.7(a)(3). (121)
“The proposed language which ties this section to the requirements in other sections of this regulation should be more clearly limited to those sections which are applicable to the facility in question. For example, requirements in section 112.8 ... should not (by the requirement in 112.7(i)) be applied to any portion of any production facility.” (L12)

Delegation. We should delegate SPCC program activities to States or explore opportunities to enter into contracts and other cooperative agreements with States. Delegating responsibility to the States would decrease costs to implement the program, and the number of inspections would increase. (27, 52, 111, 154, 185, 193) We should explore the possibility of a grants program to encourage State involvement. (27, 111)

Federal and State regulation.

Consistency with States. Urges “...EPA to be as consistent as possible with rules being adopted or developed by Washington and other states regarding standards for oil spill contingency and prevention plans given federal statutory limitations.” (185)

DOT rules. Asks why the proposed requirements are more restrictive than the United States Department of Transportation’s (DOT’s) requirements for transportation-related facilities. The DOT facilities pose a higher risk of discharging oil than our non-transportation-related facilities. (119)

Duplication. Our proposal is duplicative of other Federal and State programs, is confusing, and hinders an owner’s or operator’s ability to comply with applicable regulations. We should coordinate with other Federal and State agencies in revising the SPCC regulation. (35, 42, 82, 88, 111, 133, 139, 153, 173, 185, 193)
We should exempt all facilities currently covered by other equivalent regulatory programs. (62, 173)

Environmental overkill. “Several of these proposed regulations are more restrictive than State regulations, are environmental overkill, and would result in a facility incurring considerable expense to come into compliance.” (88)

Federal regulation unnecessary. “While the need for federal regulations is evident in some cases, this is not one of them. In many cases, the proposal overlaps programs already in place at the state level and thwarts the efforts of industry to comply with these environmental protection programs. Each state is unique in its geography, history, and environmental protection goals. Therefore, if states deem oil pollution prevention regulations are necessary to protect its citizens, the states should be allowed to draft regulations that will work to solve their own unique problems.” (139, 185, 193)

NPDES. We should exempt facilities or tanks covered by a NPDES discharge permit. (35, 173)

State regulation unnecessary. “With regard to expense, the act of encouraging State and Federal governments ‘to supplement the Federal SPCC programs’ invites yet another raid on the treasuries of companies through ‘revenue enhancing’ permit fees. Additionally, when blanket ‘encouragements’ are extended, consideration should be given to the potential for a chaotic lack of uniformity that inevitably results.” (45, 82)

One plan. We should require one plan for facilities covered under the Clean Water Act (CWA), the Resource Conservation and Recovery Act (RCRA), and SARA Title III. (80)

Other law. We should clarify that an owner or operator must comply with any applicable section of §§112.8 through 112.11 provision referenced in §112.7(i). For example, a reference in §112.7(i) to §112.8 would apply only to onshore facilities, excluding production facilities. (L12)

Response: *Consistency in rules.* As noted above, you may now use a State plan as a substitute for an SPCC Plan when the State plan meets all Federal requirements and is cross-referenced. When you use a State plan that does not meet all Federal requirements, it must be supplemented by sections that do meet all Federal requirements. At times EPA will have rules that are more stringent than States rules, and some States may have rules that are more stringent than those of EPA. If you follow more stringent State rules in your Plan, you must explain that is what you are doing.

Cross-referencing of requirements. In response to the commenter who believed that proposed §112.7(i) (redesignated in today’s rule as §112.7(j)) might require him to discuss inapplicable requirements, we note that you must address all SPCC requirements in your Plan. You must include in your Plan a complete discussion of conformance with the applicable requirements and other effective discharge prevention and containment procedures listed in part 112 or any applicable more stringent State rule, regulation, or guideline. If a requirement is not applicable to a particular type of facility, we believe that it is important for an owner or operator to explain why.

Delegation. We have no authority under the Clean Water Act to delegate our program or elements of it to the States. However, States may enact their own programs. Government agencies at the State and tribal level often exercise authority over SPCC-regulated facilities that is similar to EPA’s authority. Closer coordination with such government agencies could effectively expand SPCC’s reach and effectiveness while helping State and tribal programs administer their own activities. This could be accomplished by the development of Memorandums of Understanding (MOUs) and Interagency Agreements (IAGs) with individual States and tribes. EPA will also explore the development of a State and tribal partners program. In such a program States and tribes would participate on a voluntary basis and agree to perform some program functions and report information to a common information system in a prescribed format. EPA would maintain the databases and provide training and administrative support to participating States and tribes. This could include delivery of a fuels management class,

and the sponsorship of training and conferences in every region for States and tribes to better understand the regulated universe and to better inspect target facilities. We will also explore better data tracking and sharing with States.

Editorial suggestion. We believe that provision fits better at the end of §112.7 than in §112.7(a)(3) because it references not only the provisions of §112.7, but the applicable sections of the part which follow, as well as reference to State rules, regulations, and guidelines.

To simplify the rule language, we have amended the proposed rule to state that you must discuss all applicable requirements in the Plan instead of listing all of the sections individually.

Federal and State regulation. Both the States and EPA have authority to regulate containers storing or using oil. We believe State authority to regulate in this area and establish spill prevention programs is supported by section 311(o) of the CWA. Some States have exercised their authority to regulate while others have not. We believe that State SPCC programs are a valuable supplement to our SPCC program. When no State program exists, the Federal program becomes even more necessary.

We also note that you may use NPDES records for SPCC purposes, and may use a Best Management Practices Plan as an SPCC Plan if it meets all SPCC requirements, or may supplement so that it does. See §§112.7 (introduction), 112.7(e), 112.8(c)(3)(iv), and 112.9(b)(1).

We also note that our facilities differ from DOT facilities in many important aspects, therefore different rules are necessary.

Other law. Final §112.7(j) refers to applicable requirements in all of part 112 or more stringent State law.

Preemption. We do not preempt State rules, and defer to State rules, regulations, and guidelines that are more stringent than part 112.

Category XI: Onshore facility Plan requirements (excluding production facilities)

XI - A: Facility Drainage - §112.8(b)

Background: *Facility drainage.* In 1991, we proposed several changes to §112.7(e)(1) of the current rule on *facility drainage* at onshore facilities (excluding production facilities). We proposed to redesignate §112.7(e)(1)(i) through (iv) of the current rule as §112.8(b)(1) through (4). The proposed paragraphs addressed requirements for: facility drainage at a diked area, (b)(1); the prohibition on a flapper-type drain for diked areas, (b)(2); drainage systems for undiked areas, and a diversion system for a facility where drainage failed to meet the requirements of paragraphs (b)(1)-(3), (b)(4).

In 1991, we proposed to redesignate §112.7(e)(1)(i) of the current rule on facility drainage from diked areas, as §112.8(b)(1). We proposed to redesignate §112.7(e)(1)(ii) of the current rule, on the prohibition on flapper-type drains for diked areas, as §112.8(b)(2). We left redesignated paragraphs (b)(1) and (2) substantially the same as the equivalent provisions in the current rule. We proposed to redesignate §112.7(e)(1)(iii) of the current rule, on covered drainage systems for undiked areas, as §112.8(b)(3). However, in proposed paragraph (b)(3), we clarified that an undiked area must drain into a pond, lagoon, or catchment basin only if the area is located such that it has a reasonable potential to be contaminated by an oil discharge. We also proposed to recommend -- rather than require -- that an owner or operator avoid placing a catchment basin in an area subject to periodic flooding. We proposed to redesignate §112.7(e)(1)(iv) of the current rule as §112.8(b)(4). In paragraph (b)(4), we proposed a requirement that at a facility without a drainage system described in paragraphs (b)(1) through (3), a diversion system must retain oil in the facility, rather than return oil to the facility after the oil already was discharged.

XI-A(1) Diked storage area drainage - §112.8(b)(1)

Comments: *Applicability.* “Broadly read this could require a pond or lagoon to capture drainage from every inch of our manufacturing facilities.” Suggests limiting proposal to “areas with potential to receive spills from tanks greater than 660 gallons or areas with tanks regulated under these rules.” (126)

Electrical equipment. The diked storage area drainage requirement should not apply to electrical utility systems (such as lubrication systems and hydraulic lift systems) that use oil for operational purposes. We should not regulate these systems as we would regulate a storage tank. (125)

Secondary containment. “For facilities with site-wide containment, or that have substantial storm water draining onto and across the site, providing such detention is not practical, and, ... , may encourage/justify reliance on contingency plans in lieu of containment.” (76)

De minimis amounts of oil. It would be impossible for owners or operators to ensure that “no oil” would be discharged into water from diked areas, because the human eye is incapable of perceiving minute amounts of oil in water. We should create a more objective standard, such as the “oil sheen” standard that appears in 40 CFR 110.3. (125)

Oil/water separators. “The use of oil water separators, underflow uncontrolled discharge devices, and other apparatus can substantially reduce the potential of a significant spill of floating or other products which can be separated by gravity.” (76, 125)

Response: *Applicability.* We disagree that we should limit the scope of this section to facilities having areas with the potential to receive discharges greater than 660 gallons or areas with tanks regulated under these rules. Small discharges (that is, of 660 gallons or less) as described in §112.1(b) from diked storage areas can cause great environmental harm. See section III. F of the preamble to today’s rule for a discussion of the effects of small discharges. We disagree that this section should apply only to areas with tanks regulated under these rules because this rule applies to *regulated facilities*, not merely areas with regulated tanks or other containers. A facility may contain operating equipment within a diked storage area which could cause a discharge as described in §112.1(b).

We disagree that the requirement is not practical for facilities with site-wide containment, or that have substantial storm water draining onto and across the site. Where oil/water separators, underflow uncontrolled discharge devices, or other positive means provide equivalent environmental protection as the discharge restraints required by this section, you may use them, if you explain your reasons for nonconformance. See §112.7(a)(2). However, you must still ensure that no oil will be discharged when using alternate devices.

De minimis amounts of oil. This rule is concerned with a discharge of oil that would become a discharge as described in §112.1(b). When oil is present in water in an amount that cannot be perceived by the human eye, the discharge might not meet the description provided in 40 CFR 110.3. Therefore, such a discharge might not be a discharge in a quantity that may be harmful, and therefore not a reportable discharge under part 110. However, a discharge which is invisible to the human eye might also contain components (for example, dissolved petroleum components) which would violate applicable water quality standards, making it a reportable discharge. Therefore, we are keeping the language as proposed, other than making some editorial changes.

XI-A(2) Diked storage areas - valves used; inspection of retained stormwater - §112.8(b)(2)

Comments: *Innovative devices.* “This section should be modified to make clear whether drainage systems that allow the passage of water but not oil, such as drains equipped with imbibitor beads, may be used for facility drainage.” (39, 76, 125)

Response: *Innovative devices.* This rule does not preclude innovative devices that achieve the same environmental protection as manual open-and-closed design valves. If you do not use such valves, you must explain why. The provision for deviations in §112.7(a)(2) allows alternatives if the owner or operator states his reasons for nonconformance, and provides equivalent environmental protection by some other means. However, you may not use flapper-type drain valves to drain diked areas. And if you use alternate devices to substitute for manual, open-and-closed design valves, you must inspect and may drain retained storm water, as provided in §112.8(c)(3)(ii), (iii), and (iv), if your facility drainage drains directly into a watercourse, lake, or pond bypassing the facility treatment system.

XI-A(3) Drainage from undiked areas - §112.8(b)(3)

Comments: *Support for proposal.* We should permit facility drainage systems from undiked areas to flow into ponds, lagoons, or catchment basins designed to retain spilled oil *or* into the plant water treatment system, if that system is designed to retain spilled oil. (121) “Section 112.8(b)(3) clearly envisions and allows for facilities which have undiked oil storage areas and provides a standard for the capture of any spill from such areas through the use of catchment basins, lagoons and the like using a design of the facility’s choosing. Velsicol supports such a standard for undiked oil storage areas.” (L26)

Catchment basins. “It is highly unlikely that catchment basins will operate effectively during a flood event. Since these types of facilities could cause significant harm to the environment, EPA should require that catchment basins not be located in areas subject to flooding.” (12) “Catchment basins in areas subject to flooding essentially ensure eventual surface water contamination. The proposed regulations should be expanded to require that no new facilities used for oil or hazardous substance storage are sited in floodplains, and drainage systems for existing facilities are engineered (even if it requires pumping of contaminated water to a higher level for storage prior to treatment) so that minimal amounts of contaminated water are retained in areas subject to periodic flooding.” (44)

Applicability - generally. We should require facility drainage systems from undiked areas to flow into a pond, lagoon, or catchment basin “where possible” or “if practicable.” (54) It is impossible to specify what constitutes proper drainage control for all types of facilities. Therefore, we should retain the verb “should” as in the current rule “to allow for the exercise of good engineering practice.” (125)

Electrical equipment. “It would be very impractical to divert flow across an entire site to a pond, lagoon or catchment basin where such flow is currently uncollected or, if collected, is diverted to a storm drainage system prior to discharge. Indeed, for electrical equipment, there is an inherent inconsistency between the drainage requirements of proposed §112.8(b)(3) and the secondary containment exclusion of proposed §112.8(c)(2). ... A suggested method for reducing the impracticality and inconsistency of the proposed requirement is to limit the applicability of

§112.8(b)(3) to “systems with a potential for oil spill ‘discharge’ into or upon the navigable waters of the United States rather than the broader and more encompassing potential for ‘contamination’.” (100) The drainage requirements would impose a substantial financial burden on facility owners or operators and the burden on the electrical utility industry would outweigh the environmental benefits. (125) In urban areas, it would be impossible for owners or operators to meet the drainage requirements for transformers in vaults in large office and apartment buildings, and underneath urban streets. “Similarly, there is simply no space at such sites to construct the drainage control structures required by the proposal.” (125, 189)

Alternatives. “If it is the intent of the US EPA to require catchment for such areas, the operator should have the option of providing spill control by committing to the regular inspection of, and immediate clean-up of spills, within such areas.” (76) Asks clarification as to whether a properly sized and operated oil/water separator meets the §112.8(b)(3) requirement for drainage control. (92, 125)

Response: *Support.* We appreciate commenter support.

Applicability. We disagree that the rule language should become a recommendation because we believe that it is important to control the potential discharges the rule addresses. The rule does this by requiring retention of water within the facility from undiked areas if there is no provision for flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. Where a diversion system is infeasible, if you explain your reasons for nonconformance, you may provide equivalent environmental protection by an alternate means.

In response to the commenter who questioned the applicability of this paragraph to areas under aboveground piping and loading/unloading areas, we note that both areas are subject to the rule’s requirements if they are undiked.

Electrical equipment. The requirements of paragraph (b)(3) apply to a facility with electrical equipment. If you determine it is infeasible to comply with the requirements of the paragraph, you must explain your reasons for nonconformance, and provide equivalent environmental protection. 40 CFR 112.7(a)(2).

Alternatives. The rule does not limit you to the use of drainage trenches for undiked areas. Other forms of secondary containment may be acceptable. The rule only prescribes requirements for the drainage of diked areas, but does not mandate the use of diked areas. However, if you do use diked areas, the rule prescribes minimum requirements for drainage of those areas. Also, if the requirement is not practical, you may explain your reasons for nonconformance and provide equivalent environmental protection under §112.7(a)(2).

XI-A(4) Diversion systems - §112.8(b)(4)

Comments: “Ohio EPA agrees with the proposed language regarding facility drainage. The proposed language requires, rather than suggests, that facility drainage flow to a catchment basin. Also, oil is to be ‘retained’ at the facility, rather than ‘returned.’ While we understand that this change implies that the spill should not leave the facility boundaries, it should be further clarified.” (27) We should require the owner or operator either to retain oil within the facility or return it to the facility, whichever is applicable. The diversion system requirement should apply only to the “petroleum areas of the facility such as tanks, pipes, racks, and diked areas” because “drainage from the rest of the facility should not be contaminated and thus should not have to be diverted.” (54)

Response: The rule accomplishes the aim of retaining within the facility minimal amounts of contaminated water in undiked areas subject to periodic flooding. It is better that a diversion system retain rather than allow oil to leave the facility, thus enhancing the prevention goals of the rule. Furthermore, it should be easier to retain discharged oil rather than retrieve oil that has been discharged from the facility. Therefore, we agree with the commenter that “retained” oil is oil that never leaves the facility. We also agree that the rule applies only to drainage from the “petroleum” (or other oil) areas of the facility such as tanks, pipes, racks, and diked areas, because the purpose of the SPCC rule is to prevent discharges of oil, not of all runoff contaminants. Amendment of the rule language is unnecessary because all of the rule applies only to “petroleum” or “oil” areas of the facility. Therefore, we have promulgated the rule language as proposed with a minor editorial change.

XI-A(5) Drainage systems - §112.8(b)(5)

Comments: *PE certification.* We should add a section to the rule requiring that Professional Engineers (PEs) certify the design and construction of the storm water drainage system and the sanitary sewer system, because the PE is in the best position to prepare the spill containment parts of the SPCC Plan. (47)

Response: *PE certification.* PE certification is already required for the design of stormwater drainage and sanitary sewer systems by current rules because those systems are a technical element of the Plan. Therefore, we are keeping the language as proposed.

XI-A(6) FEMA requirements - Proposed §112.8(b)(6)

Comments for this section were combined with comments for section XII-D.

XI - B: Bulk storage containers - §112.8(c)

XI-B(1) Material and construction - §112.8(c)(1)

Background: Section 112.7(e)(2)(i) of the current rule (redesignated as §112.8(c)(1) of the final rule) requires an owner or operator of an onshore bulk storage facility to ensure that the material and construction of tanks used to store oil are compatible with the material stored and conditions of storage. In §112.8(c)(1), we proposed a new recommendation that the construction, materials, installation, and use of tanks conform with relevant portions of industry standards such as API, NFPA, UL, or ASME standards.

Comments: *Support for proposal.* “Based on the preamble, it is apparent that the use of industry standards is intended to be a recommendation and not a requirements. Valvoline fully supports the use of standards in this manner as they were not developed for use as regulatory requirements and are not applicable or necessary in all possible situations. As a result, their use should be discretionary utilizing good engineering practices as appropriate. However, the wording utilized in section 112.8(c)(1) taken in conjunction with section 112.7(a) is contradictory as to whether or not the use of industry standards is a recommendation or a requirement.” (67, 95, 102, 115, 148)

Opposition to proposal. We should not place recommendations in the regulation. We should not ask owners or operators to consider good engineering practice since this makes the regulation unenforceable. Instead, we should tell the owner, operator, or certifying engineer what good engineering practice requires. We should substitute proposed §112.8(c)(2) with the proposed §112.8(c)(1) text and delete the recommendation, which is “advisory and unenforceable.” (121)

Additional industry standards. In §112.8(c)(1), we should reference the Steel Tank Institute (STI) standard F911-91, “Standard for Unitized Steel Aboveground Storage Tank Systems with Open Top Secondary Containment.” (140) The industry standards listed in the preamble are “extremely important,” but these standards do not address the physical site and its surrounding lands and waters. (L4)

Requirement instead. The rule should require, not recommend, that tanks meet industry standards. “At a date certain, all existing tanks should be upgraded to meet industry codes. Moreover, all new and reconstructed tanks should be subject to applicable codes.” (44) We should change §112.8(c)(1) to require the following: “All tanks constructed after the effective date of this part must be constructed to one of the following industry standards (list here the standards acceptable to EPA). The owner or operator shall retain records, as part of the (SPCC Plan), to show which standard was used in the construction of the tank, and a certification plate, setting forth the standard to which the tank was constructed and the date of its construction shall be permanently affixed to the tank.” (121)

Response: *Requirement v. recommendation.* The first sentence of the proposed rule indeed contemplated a requirement, i.e., that no container may be used for the storage of oil unless its material and construction are compatible with the material stored and the conditions of storage, such as pressure or temperature. The second sentence, which was clearly a recommendation, has been deleted from the rule because we have decided to remove all recommendations from the rule language. Rules are mandates,

and we do not wish to confuse the regulated community as to what actions are mandatory and what actions are discretionary. The Professional Engineer must, pursuant to §112.3(d)(1)(iii), certify that he has considered applicable industry standards in the preparation of the Plan. While he must consider such standards, use of any particular standards are a matter of good engineering practice.

Additional industry standards. While we do not specify particular standards in the rule, we endorse the use of industry standards. We note that the discussion of many sections of the rule addresses particular industry standards.

Section 112.8(c)(2). We will address issues relating to §112.8(c)(2) under the discussion of that section.

XI - B(2) Secondary containment for bulk storage containers at onshore facilities - §112.8(c)(2)

Background: In 1991, we proposed to redesignated the §112.7(e)(2)(ii) secondary containment requirements of the current rule as §112.8(c)(2), and make some revisions.

We gave notice in the preamble that “sufficient freeboard” to contain precipitation is freeboard sufficient to contain a 25-year storm event. We also proposed that diked areas be sufficiently impervious to contain spilled oil for at least 72 hours. The rationale for the 72-hour standard was to allow time for the discovery and removal of a discharge.

Electrical equipment. In the 1991 preamble, we noted that certain facilities may have equipment such as electrical transformers that contain significant quantities of oil for operations rather than for storage. For safety and other considerations, we determined that we should not require an owner or operator of such oil-filled equipment to comply with §112.8(c) or §112.9(d) secondary containment requirements, because storage of oil in bulk is not the primary purpose of such equipment. Therefore, we stated that an owner or operator of a facility with equipment containing oil for ancillary purposes does not need to provide secondary containment for this equipment or implement the other provisions of proposed §112.8(c) (or §112.9(d). 56 FR 54623. However, an owner or operator of oil-filled equipment must meet other applicable SPCC requirements including the requirements of §112.7(c), to provide appropriate containment and diversionary structures to prevent discharged oil from reaching navigable waters.

Comments: *De minimis containers.* “Request that some de minimis limit be set for requiring secondary containment. While in some cases secondary containment for the largest tank is acceptable, can manufacturers may have several smaller tanks, none of which should be considered large.” (62)

Designations. “In extraordinary circumstances, EPA Solid Waste and Emergency Response should designate local fire regulatory authorities and/or state and local EPA’s to make decisions concerning ‘deemed equivalency’ for secondary containment, as is done by the UST section of EPA.” (65)

Double-walled or vaulted tanks. We should allow an owner or operator to use pre-fabricated, vaulted, or double-walled tanks with secondary containment under §112.8(c). (65, 79, 140, 144, 179)

Facility size. “Recognizing EPA’s limited funding and enforcement resources, EPA should consider allowing the state EPA’s and the fire regulatory authorities to continue to regulate the small ‘throughput’ vaulted tank industry which fire regulatory authorities have defined as 6,000 per tank and 18,000 gallons per site.” (65, 79)

Fire codes. “Deem as equivalent for EPA purposes, the secondary containment of VAST technology which meets any of EPA-recognized industry standards of the model fire codes of NFPA, BOCA, or UFC.” (65)

Freeboard. Double-walled steel tanks with integral secondary containment, and other factory-fabricated tanks with secondary containment are designed so that precipitation does not collect within the secondary containment. (65, 140) Asks us to address the technical construction design of steel tanks with factory-fabricated secondary containment in the §112.8(c)(2) freeboard requirements. (140) A double-walled “F921-92” AST or its equivalent does not need freeboard because it is entirely enclosed; the outside tank is larger than the inside tank and will hold the entire contents of the primary tank. (179)

Impermeability. VASTs are impervious to oil for 72 hours. (65)

Outer-steel wrap. The secondary containment provided by a factory-fabricated, “integral outer-steel wrap” is acceptable if the system has additional mechanisms to prevent overfill and provide containment. (140)

Regional opposition. “Working mostly with fire prevention personnel and codes, but with environmental protection of equal concern, several styles of tanks have been developed which will meet the intent of the proposed regulations for protection of the environment, but based on an interpretation from Region 10 have not been allowed to be used.” (108, 122)

Vandalism and fire. A VAST’s concrete encasement provides protection against vandalism and fire. VASTs allow an owner or operator to dike the contents of every tank, rather than only the single largest tank. (65)

Editorial suggestions. Recommends that we move the proposed §112.8(c)(2) on secondary containment requirements to the proposed §112.8(c)(3) on drainage requirements. Asks that we change the phrase “all bulk storage tank installations” to “tanks” in the proposed §112.8(c)(2) sentence, “All bulk storage tank installations should be constructed so that a secondary means of containment is provided for the entire contents of the largest single tank and sufficient freeboard to allow for precipitation.” (121)

Electrical or other operating equipment. Support for proposal that an owner/operator who has equipment containing oil for ancillary purposes need not have secondary containment nor comply with the §112.8(c) and §112.9(d) bulk storage container provisions. (66, 103, 125, 132, 134, 156, 164, L7, L20)

Fire, hazard, safety considerations. Installing secondary containment for electrical equipment may create electrical and fire hazards. (125) We should clarify what “safety and other considerations” make it appropriate to exclude electrical equipment from secondary containment requirements. (L17)

Leak detection. An owner or operator can immediately detect a leak from electrical equipment because a leak would trigger the alarm system. (66, 98, 138, L20) Electrical equipment is constructed with pressure relief devices and that a leak from one unit would not affect another unit. (L20)

Operating equipment. We should exclude from the secondary containment requirements: trash compactors and process or water pumps; lubricating oil used in engines, turbines, compressors, and expanders; oil circuit breakers and auto boosters; oil held temporarily in the internal or external storage compartment of an oil/water separator; oil used in cranes, jacks, elevators, and forklifts; hydraulic lift systems; throughput-type tanks; wastewater treatment tanks; and capacitors and oil-based heaters. (62, 65, 66, 102, 107, 125, 132, L7)

Manifolded tanks. “The term ‘single largest tank’ should be modified to include tanks which are manifolded together, or otherwise have overflow capabilities.” (27)

Seventy-two-hour impermeability standard. See the discussion on §112.7(c) for the comments on this subject.

Secondary containment, in general.

Supports requirement. Secondary containment for storage containers, including mobile storage containers, should be adequate to contain the contents of the largest, single tank within the secondary containment with freeboard sufficient for precipitation from a 25-year storm event. The State of New Jersey has this requirement. (27, 147)

Opposes requirement. Requiring secondary containment for small ASTs is unduly burdensome and impractical, and would require owners or operators to staff and monitor otherwise unstaffed sites. (69) Asks us to consider promulgating a “more realistic” provision for secondary containment systems (71). We have no justification for requiring an owner or operator to provide secondary containment for the contents of the largest single tank, or for requiring an owner or operator to provide freeboard sufficient to allow for precipitation. The commenter cited our “Analysis of Implementing Permitting Activities for Stormwater Discharges

Associated with Industrial Activity" document as evidence of the minimal risk posed by secondary containment overflow (July 1991). (173) We should recognize that secondary containment installation is not possible for all tanks (e.g., indoor tanks). (175)

Contingency planning instead. Asks us to follow the Federal Aviation Administration's example, and allow an owner or operator of a facility with "small numbers of small capacity ASTs" to conduct contingency planning and training instead of installing secondary containment. We should use the fire prevention code to define the term "small numbers of small capacity ASTs" as "less than a total capacity of 6,000 gallons per facility." (69)

Largest single tank. Not all facilities "have enough property to provide this volume of containment," which would result in an enormous operational burden for existing facilities. However, we should require secondary containment for existing tanks with a volume greater than 100,000 gallons. (90) "Impervious containment of a volume larger than the largest single tank may not be necessary for all tanks." (90,126)

Methods. "In other words, we recommend that the free choice of design offered to the facility by 112.8(b)(3) be preserved in 112.8(c)(2) and not be narrowed to allow only drainage trench enclosures in cases where diking is not used." (L26)

Oil/water separators. Asks us to allow properly sized and operated oil/water separators to meet the drainage control and secondary containment requirements. (98)

Phase-in. We should phase-in secondary containment requirements, and apply them to large facilities only. (116)

Underground cable systems. "Even if secondary containment systems could be installed, the costs are likely to be prohibitive. ... Electric utilities already have operational response plans to address leaks as part of their planning to prevent disruption of service." (125)

"Should to shall" cost. We reduced the impact of the proposal by failing to consider the cost of changing "should" to "shall," and cited the secondary containment requirement as an example. The proposed rule requires an owner or operator to equip all tank batteries with secondary containment, although many petroleum extraction industry tank batteries do not have secondary containment because of the cost or lack of need. (L27)

Snow and ice. "In the case of many Rocky Mountain fields, secondary containment in the form of dikes is worthless because of drifting snow which turns to ice filling the diked area." (L27)

Sufficient freeboard.

Alternatives to freeboard. “Also, the regulations should specify that maintaining any freeboard does not apply when rainguards are used to divert storm water and keep it from accumulating in the diked area.” (88) “E&P operations should have the option to use portable/permanent pumps or water hauler trucks for removal of any 25 year storm water event. KMS believes the more appropriate and applicable standard is the 10-year event.” (114)

Clarification needed. We should clarify what we mean in §112.8(c)(2) by “sufficient freeboard.” (54, 154, 179, L18)

10-year storm event. It would be adequate to provide freeboard sufficient to contain precipitation from a 10-year storm event, or more specifically, a 10-year, 24-hour storm event. (48, 80, 87, 95, 102, 114, 133, L3, L12)

25-year storm event.

Opposes recommendation. “It will be difficult and would require meteorological studies over a period of time to determine what freeboard is sufficient to contain a 25 year storm event.” (34, 53) “We should consider as sufficient, a tank’s ability to contain 110 percent of the capacity of the largest tank, which is an accepted industry standard and consistent with good engineering practice. (34, 48, 54, 133, L7) “We feel that the 25 year storm containment recommendation is unduly stringent, and would impose considerable costs without any significant benefits.” (80) We should allow flexibility for determining whether a facility has adequate freeboard. There is not enough space to retrofit the containment areas required to provide freeboard for a 25-year storm for all facilities. (88) “The chances of a secondary containment dike being full of oil at the same time that a 24-hour, 25-year storm event takes place is astronomically small. Freeboard capable of holding a 24-hour, 10-year storm event is sufficient.” (102) The volume from a 25-year storm event should remain as a recommendation, but we should not specify the amount of precipitation accumulated from a 25-year storm event because it will vary depending on the location. States may require a specific freeboard capacity. (143) “The rubber industry is concerned that the 25-year freeboard ‘recommendation’ will be interpreted as a ‘requirement’.” (L3) “This ‘requirement’ may be sufficient for new storage tanks. Secondary containment for previously installed tanks, however, may have been designed for 100% of the largest tank, 110% of the largest tank, 100% of the largest tank plus 0.5 inches of rain, or another viable measure. EPA should provide some variance to allow existing containment to meet the intent of the law, and thereby not requiring small additions to the containment structure with minimum resulting benefit.” (L7)

Clarification needed. We should clarify what we meant by “sufficient to contain a 25-year storm event.” (54) Asks clarification of the duration and the recurrence frequency of the 25-year storm event. (76, 87, 102, 114)

Response: *De minimis containers.* We have established a *de minimis* container size of less than 55 gallons. You do not have to provide secondary containment for containers of less than 55 gallons.

Designations. We disagree that we should designate State and local authorities to determine whether a tank meets the §112.8(c) secondary containment requirements. We have no authority under the Clean Water Act to delegate elements of the SPCC program to State or local governments. We likewise disagree that we should that we should designate Federal authorities, including our regional offices, to determine whether a container meets the §112.8(c) secondary containment requirements. Such a determination is in the first instance one for the owner or operator to make in consultation with his Professional Engineer. If the Regional Administrator disagrees with this determination, he may require the owner or operator to amend his Plan.

Double-walled or vaulted tanks. The term “vaulted tank” has been used to describe both double-walled tanks (especially those with a concrete outer shell) and tanks inside underground vaults, rooms, or crawl spaces. While double-walled or vaulted tanks are subject to secondary containment requirements, shop-fabricated double-walled aboveground storage tanks equipped with adequate technical spill and leak prevention options might provide sufficient equivalent secondary containment as that required under §112.7(c). Such options include overfill alarms, flow shutoff or restrictor devices, and constant monitoring of product transfers. In the case of vaulted tanks, the Professional Engineer must determine whether the vault meets the requirements for secondary containment in §112.7(c). This determination should include an evaluation of drainage systems and of sumps or pumps which could cause a discharge of oil outside the vault. Industry standards for vaulted tanks often require the vaults to be liquid tight, which if sized correctly, may meet the secondary containment requirement.

There might also be other examples of such alternative systems. Larger, field-erected tanks (generally over 12,000 gallons) should not be without more traditional forms of secondary containment as listed in §112.7(c) because of the higher risk of uncontrolled discharges from such tanks due to tank size, design, and pumping rates.

Editorial suggestions. We disagree that we move should §112.8(c)(2) secondary containment requirements to §112.8(c)(3) with drainage requirements. Drainage and secondary containment are discrete subjects which should be handled separately.

In the first sentence, “spill” becomes “discharge.” Also in that sentence, “contents of the largest single tank” becomes “capacity of the largest single container.” This is merely a clarification and has always been the intent of the rule. The contents of a container may vary from day to day, but the capacity remains the same. In discussing capacity, we noted in the 1991 preamble that “the oil storage *capacity* (emphasis added) of the equipment, however, must be included in determining the total storage capacity of the facility, which determines whether a facility is subject to the Oil Pollution Prevention regulation.” 56 FR 54623. We discuss this capacity in the context of the general requirements for secondary containment. Thus, it is clear that we have always intended

capacity to be the determinative factor in both subjecting a facility to the rule and in determining the need for secondary containment.

We also deleted the phrase “but they may not always be appropriate” from the third sentence of the paragraph because it is confusing when compared to the text of §112.7(d). Under §112.7(d), if secondary containment is not practicable, you may provide a contingency plan in your SPCC Plan and otherwise comply with that section. In the last sentence, “plant” becomes “facility.” Also in that sentence, the phrase “so that a spill could terminate....” becomes “so that any discharge will terminate....”

Electrical or other operating equipment. Because electrical, operating, manufacturing equipment are not bulk storage containers, the §112.8(c)(2) secondary containment requirement is inapplicable to those devices or equipment. 56 FR 54623. However, the general secondary containment requirement at §112.7(c) is applicable. If it is not practicable from a matter of good engineering practice (for example, because of safety reasons or the danger of fire or explosion) to install secondary containment for oil-filled equipment, the owner or operator must provide a contingency plan following part 109 and otherwise comply with §112.7(d).

Model fire codes. Compliance with a model fire code may be acceptable under §112.8(c) if the code meets the requirements of the section. We note that we meet with fire code officials from time to time.

Secondary containment, in general. A primary containment system is the container or equipment in which oil is stored or used. Secondary containment is a requirement for all bulk storage facilities, large or small, manned or unmanned; and for facilities that use oil-filled equipment; whenever practicable. Such containment must at least provide for the capacity of the largest single tank with sufficient freeboard for precipitation. A discharge as described in §112.1(b) from a small facility may be as environmentally harmful as such a discharge from a large facility, depending on the surrounding environment. Likewise, a discharge from a manned facility needs to be contained just as a discharge from an unmanned one. A phase-in of these requirements is not appropriate because secondary containment is already required under current rules. When secondary containment is not practicable, the owner or operator of a facility may deviate from the requirement under §112.7(d), explain the rationale in the Plan, provide a contingency plan following the provisions of 40 CFR part 109, and otherwise comply with §112.7(d).

Because a pit used as a form of secondary containment may pose a threat to birds and wildlife, we encourage an owner or operator who uses a pit to take measures to mitigate the effect of the pit on birds and wildlife. Such measures may include netting, fences, or other means to keep birds or animals away. In some cases, pits may also cause a discharge as described in §112.1(b). The discharge may occur when oil spills over the top of the pit or when oil seeps through the ground into groundwater, and thence to navigable waters or adjoining shorelines. Therefore, we recommend that an owner or operator not use pits in an area where such pit may prove a source of such discharges.

Should the oil reach navigable waters or adjoining shorelines, it is a reportable discharge under 40 CFR 110.6.

We disagree that the rule is duplicative of NPDES rules. Forseeable or chronic point source discharges that are permitted under CWA section 402, and that are either due to causes associated with the manufacturing or other commercial activities in which the discharger is engaged or due to the operation of treatment facilities required by the NPDES permit, are to be regulated under the NPDES program. “Classic spill” situations are subject to the requirements of CWA section 311. Such spills are governed by section 311 even where the discharger holds a valid and effective NPDES permit under section 402. 52 FR 10712, 10714. Therefore, the typical bulk storage facility with no permitted discharge or treatment facility would not be under the NPDES rules. The secondary containment requirements of the rule apply to bulk storage containers and their purpose is to help prevent discharges as described in §112.1(b) by containing discharged oil. NPDES rules, on the other hand, may at times require secondary containment, but do not always. Furthermore, NPDES rules may not always apply to bulk storage facilities. Therefore, the rule is not always duplicative of NPDES rules. Where it is duplicative, an owner or operator of a facility subject to NPDES rules may use that portion of his Best Management Practice Plan as part of his SPCC Plan.

Alternatives. Oil/water separators. The rule does not mandate the use of any specific means of secondary containment. Any system that achieves the purpose of the rule is acceptable. That purpose is to prevent discharges as described in §112.1(b).

Phase-in. There is no need for a phase-in of secondary containment requirements because they are already in effect and apply to all facilities, large and small.

Snow and ice. We disagree that secondary containment is unnecessary for facilities in which drifting snow turns to ice in the diked area. Such snow or ice may be contaminated with oil and cause harm to the environment if it escapes the facility.

Seventy-two-hour impermeability standard. As noted above, we have decided to withdraw the proposal for the 72-hour impermeability standard and retain the current standard that diked areas must be sufficiently impervious to contain oil. We take this step because we agree with commenters that the purpose of secondary containment is to contain oil from reaching waters of the United States. The rationale for the 72-hour standard was to allow time for the discovery and removal of an oil spill. We believe that an owner or operator of a facility should have flexibility in how to prevent discharges as described in §112.1(b), and that any method of containment that achieves that end is sufficient. Should such containment fail, an owner or operator must immediately clean up any discharged oil. Similarly, we intend that the purpose of the “sufficiently impervious” standard is to prevent discharges as described in §112.1(b) by ensuring that diked areas can contain oil and are sufficiently impervious to prevent such discharges.

“Should to shall” cost. There is no cost in the “should to shall to must” change because the change is merely editorial.

Sufficient freeboard. An essential part of secondary containment is sufficient freeboard to contain precipitation. Whatever method you use to calculate the amount of freeboard that is “sufficient” must be documented in the Plan. We believe that the proper standard of “sufficient freeboard” to contain precipitation is that amount necessary to contain precipitation from a 25-year, 24-hour storm event. That standard allows flexibility for varying climatic conditions. It is also the standard required for certain tank systems storing or treating hazardous waste. See, for example, 40 CFR 265.1(e)(1)(ii) and (e)(2)(ii). While we believe that 25-year, 24-hour storm event standard is appropriate for most facilities and protective of the environment, we are not making it a rule standard because of the difficulty and expense for some facilities of securing recent information concerning such storm events at this time. Recent data does not exist for all areas of the United States. Furthermore, available data may be costly for small operators to secure. Should recent and inexpensive information concerning a 25-year, 24-hour storm event for any part of the United States become easily accessible, we will reconsider proposing such a standard.

XI - B(3) Drainage of rainwater - §112.8(c)(3)

Issues. In 1991, we also proposed several changes to §112.7(e)(2) of the current rule on *bulk storage tanks* at onshore facilities (excluding production facilities). Specifically, we proposed to redesignate §112.7(e)(2)(iii) as §112.8(c)(3). Proposed paragraph (c)(3) addressed drainage from diked areas around bulk storage tank installations. It contains requirements for drainage of uncontaminated rainwater from a diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system.

Comments: *NPDES.* Records of discharges that do not violate water quality standards are unnecessary. “It is more logical and less confusing to train operators to report by exception.” (88) “To avoid unnecessarily duplicative and overlapping work, we request that the Agency clarify that records and testing normally required for a permitted outfall under the NPDES program are adequate to fulfill the requirements under this section.” (92)

Methods. The proposed requirement in §112.8(c)(3) to close and seal drains on dikes or equivalent measures at all times, except when rainwater is being drained, precludes engineering measures, such as standpipes, based on good engineering practice. Requiring the closing of standpipe valves defeats the purpose of installing the valves in the first place. (28, 101, 165, L15, L27)

Response: *Methods.* Acceptable measures might, depending on good engineering practice, include using structures such as standpipes designed to handle flow-through conditions at certain oil production operations, where large volumes of water may be

directed to oil storage tanks if water discharge lines on oil-water separators become plugged.

NPDES. We are not adopting the NPDES rules for SPCC purposes, but are only offering an alternative for recordkeeping. The intent of the rule is that you may, if you choose, use the NPDES stormwater discharge records in lieu of records specifically created for SPCC purposes. We are not incorporating the NPDES requirements into our rules by reference.

This paragraph applies to discharges of rainwater from diked areas that may contain any type of oil, including animal fats and vegetable oils. The only purpose of this paragraph is to offer a recordkeeping option so that you do not have to create a duplicate set of records for SPCC purposes, when adequate records created for NPDES purposes already exist.

XI - B(4) Completely buried tanks; corrosion protection - §112.8(c)(4)

Background: In 1991, we redesignated and repropose current §112.7(e)(2)(iv) as §112.8(c)(4), to require that an owner or operator protect new completely buried storage tanks installed on or after January 10, 1974, from corrosion by coatings, cathodic protection, or other effective methods compatible with local soil conditions.

In 1991, we also proposed changing the §112.7(e)(2)(iv) requirement for regular pressure testing to a recommendation for regular leak testing of buried tanks. We specified leak testing rather than pressure testing to be consistent with many State rules.

Because completely buried tanks currently subject to the technical requirements of 40 CFR parts 280 and 281, the underground storage tank (UST) regulations, are generally exempted from SPCC requirements under proposed §112.1(d)(4), §112.8(c)(4) applies only to tanks not subject to 40 CFR part 280 or 281.

Comments: *Part 280 standards.* We should avoid duplicative environmental requirements by expressly stating that metallic USTs must meet the “appropriate requirements of 40 CFR 280.” (44, 67, 85, 111, 175, 180)

Corrosion protection.

Support for proposal. “We support the proposed requirement for protective coating and cathodic protection for new or replaced buried piping, regardless of soil conditions.” (L17)

Opposition to proposal.

“Unenforceable.” Proposal “is unenforceable.” (121)

Monitoring effectiveness. “...(T)he regulation contains no discussion of cathodic protection for tank bottoms in contact with soil or fill materials. Also the regulation

includes no requirements for monitoring the effectiveness of cathodic protection of buried tanks and piping.” (16)

Leak testing.

Support for proposal. Support for our proposal for discretionary leak (or discharge) testing with some modifications. (48, 67, 85, 102) “ILMA agrees that making this a recommended, rather than mandatory, practice is consistent with the goal of using good engineering practice. This offers regulated facilities the flexibility to monitor these tanks with a frequency necessitated by site-specific circumstances, such as the ages of the tanks or soil conditions.” (48)

Opposition to proposal. “As to leak testing, there is no current requirement for integrity testing of buried piping at storage facilities. At very large facilities it may be practical to conduct the type of testing proposed. However, for small and medium facilities it is impractical and would be extremely costly to implement this recommended practice.” (34)

Response: *Corrosion protection.* We agree in principle that all completely buried tanks should have some type of corrosion protection, but as proposed, we will only extend that requirement to new completely buried metallic storage tanks. Because corrosion protection is a feature of the current rule (see §112.7(e)(2)(iv)), the requirement applies to completely buried metallic tanks installed on or after January 10, 1974. The requirement is enforceable because it is a procedure or method to prevent the discharge of oil. See section 311(j)(1)(C) of the CWA. Most owners or operators of completely buried storage tanks will be exempted from part 112 under this rule because such tanks are subject to all of the technical requirements of 40 CFR part 280 or a State program approved under 40 CFR 281. Those tanks subject to 40 CFR part 280 or a State program approved under 40 CFR part 281 will follow the corrosion protection provisions of that rule, which provides comparable environmental protection. Those that remain subject to the SPCC regulation must comply with this paragraph.

The rule requires corrosion protection for completely buried metallic tanks by a method compatible with local soil conditions. Local soil conditions might include fill material. The method of such corrosion protection is a question of good engineering practice which will vary from facility to facility. You should monitor such corrosion protection for effectiveness, in order to be sure that the method of protection you choose remains protective. See §112.8(d)(1) for a discussion of corrosion protection for buried piping.

UST standards. UST or other industry standards may satisfy SPCC requirements.

Leak testing. The current SPCC rule contains a provision calling for the “regular pressure testing” of buried metallic storage tanks. 40 CFR 112.7(e)(2)(iv). We proposed in 1991 a recommendation that such buried tanks be subject to regular “leak testing.” Proposed §112.8(c)(4). Leak testing for purposes of this paragraph is testing to ensure

liquid tightness of container and whether it may discharge oil. We specified leak testing in the proposal, instead of pressure testing, in order to be consistent with many State regulations and because the technology on such testing was rapidly evolving. 56 FR at 54623.

We are modifying the leak testing recommendation to make it a requirement. We agree with the commenter who argued that such testing should be mandatory because recommendations may not often be followed. Appropriate methods of testing should be selected based on good engineering practice. Whatever method and schedule for testing the PE selects must be described in the Plan. Testing under the standards set out in 40 CFR part 280 or a State program approved under 40 CFR part 281 is certainly acceptable (as we suggested in the proposed rule). "Regular testing" means testing in accordance with industry standards or at a frequency sufficient to prevent leaks.

XI - B(5) Partially buried or bunkered tanks - §112.8(c)(5)

Background: Under §112.7(e)(2)(v) of the current rule, a partially buried metallic tank must be avoided unless the shell is coated, since damp earth can cause rapid corrosion of a buried tank, especially where air and soil contact. In 1991, we proposed in §112.8(c)(5) to *recommend* against storing oil in partially buried or bunkered metallic tanks. However, if such tanks are used, we proposed to require that the owner or operator protect the buried or bunkered metallic tank from corrosion by using coatings, cathodic protection, or other methods compatible with local soil conditions.

Comments: *Applicability.* We should clarify that the proposed recommendation applies only to new partially buried tanks. (54)

Editorial suggestion. We could omit §112.8(c)(5) by removing the term "partially buried tanks." (180)

Requirement v. recommendation. Recommends that we delete the first sentence of §112.8(c)(5) because it is purely advisory. (121)

Response: *Applicability.* The requirement to avoid the use of such tanks, unless they are protected from corrosion, applies to all partially buried metallic tanks, installed at any time. This requirement is in the current rule and applies to tanks installed since the effective date of the rule in 1974.

Editorial suggestion. We disagree that we should remove the term "partially buried tanks" or delete §112.8(c)(5). Such a deletion would remove partially buried tanks from the corrosion protection requirements of the rule.

Requirement v. recommendation. Due to the risk of discharge caused by corrosion, we decided to keep the current requirement to not use partially buried metallic tanks, unless the buried section of such tanks are protected from corrosion. The requirement to not

use such tanks, unless they are protected from corrosion, applies to all partially buried metallic tanks, installed at any time.

XI - B(6) Integrity testing - §112.8(c)(6)

Background: Current §112.7(e)(2)(vi) requires an owner or operator to conduct periodic integrity testing of aboveground bulk storage tanks, taking into account tank design and using such techniques as hydrostatic testing, visual inspection, or a system of non-destructive shell thickness testing. In 1991, we proposed to redesignate §112.7(e)(2)(vi) as §112.8(c)(6), and to require that an owner or operator of a facility with adequate secondary containment conduct integrity testing of aboveground bulk storage tanks every ten years and when there are material repairs to an aboveground tank. We also proposed to maintain the current requirement for keeping comparison records and for inspecting the tank's supports and foundations. Further, we proposed to maintain the current requirement for operating personnel to observe the outside of the tank frequently for signs of deterioration, leaks, or oil accumulation inside diked areas.

Comments: *Support for proposal.* "Ashland supports the agency's proposal to require integrity testing of bulk storage tanks once every ten years and when material repairs are performed." (83, 102, L35)

Opposition to proposal.

Air emissions, fatalities. The release of gas from testing would increase air emissions and the risk of fatalities. Tanks "in severe environments or service" may not have a ten-year life expectancy. (67)

Cost, out-of-service tanks. Owners or operators would have to build replacement tanks for the 10 percent of tanks taken out-of-service every year for testing. (67)

Logistically difficult. Internally inspecting tanks is costly and logistically difficult. (L35)

Environmental threat. Integrity testing is unwarranted since many tanks are inspected daily, and tanks located inside buildings are less likely to pose an environmental threat than outside tanks. (71) The ten-year testing requirement is costly and may not have an environmental benefit, since secondary containment contains the tank's contents if there is a failure. (90)

Residual oil. "A ten-year testing cycle is simply not justified for residual oil tanks. Such relatively frequent forced outages will likely impact system reliability in the context of maintaining reserve capacity requirements if, for example, a particular generating unit is supplied from a specific fuel oil tank or an alternative fuel is unavailable. And perhaps more important, the compensating mechanism for avoiding station outages, i.e., to barge or truck-in fuel in lieu of tank supplies, is far more environmentally threatening. Consequently, Con Edison recommends that residual oil tanks be excluded from the testing frequency proposed in the

revised section 112.8(c)(6) or alternatively, that the testing of these tanks be tied to practical operational factors such as scheduled maintenance outages.” (100, L35)

Unnecessary, hazardous waste. Integrity testing is unnecessary because “tanks that store oil have a lower rust potential” (71) and “cleaning would generate more hazardous waste” (67).

Applicability.

Airport fuel systems. “This recommendation does not mention airport fuel hydrant systems associated with above ground fuel storage facilities” (107)

Electrical equipment. Tank integrity testing requirement for electric equipment containing oil is burdensome and has no environmental benefit. Owners or operators would have to test such equipment while it was out-of-service, which is impractical. (92) “While the electric utilities generally believe that this is a reasonable proposal, we believe that two exclusions should be provided. First, ..., an exclusion should be provided for tanks used to store oils with a pour point greater than 60 degrees Fahrenheit. Such tanks pose little risk to navigable waters because the oil does not flow freely. ... A second exclusion should be provided for tanks that are capable of visible inspection on all sides and utilize secondary containment.” (92, 125, L2)

Phase-in.

10 years. Suggests testing be phased in over the “next ten years after enactment of the final rule.” (92, 125)

UST model. “There should be a phase-in period for testing of aboveground tanks subject to 112.8(c)(6). This could be based on age of the tank and modeled after the UST program requirements for phase-in of leak detection.” (161)

Small facilities. We should differentiate between large and small facilities because the ten-year testing requirement is inappropriate for small tanks at small facilities. (34) “GM also believes that mandatory testing of aboveground tanks every ten years at a minimum, is unnecessary for small volume tanks and at facilities that have incorporated secondary containment structures.” (90) We should consider exempting tanks based on size and tanks with 100 percent containment. (191)

Suggested threshold levels.

Less than 2,000 gallons. We should exempt from the testing requirement, tanks contained within a building or with a maximum capacity of less than 2,000 gallons,

tanks with all sides visible, and tanks and any associated piping and ancillary equipment that are visually inspected monthly. (71)

10,000 gallons or more. We should require an owner or operator to inspect aboveground tanks with a capacity of 10,000 gallons or more internally for structural soundness, tank bottom corrosion, and wall thinning. An owner or operator could conduct hydrostatic testing between ten year intervals, but not as a substitute for a thorough inspection. (111)

Type of oil stored. “The proposed amendment does not properly reflect the difference between groundwater and surface water impact potential of different petroleum products such as gasoline, # 2 fuel oil or # 6 fuel oil nor do the proposed changes differentiate or give consideration to petroleum storage facilities over groundwater deep recharge areas as opposed to those in less sensitive hydrogeologic zones.” (100, L35)

Heavy oils. Re # 5 and # 6 fuel oil tanks: “It is very expensive and time-consuming to perform integrity tests on such tanks and because of the viscosity and pour point of these products, there is little likelihood that these products could flow and cause any substantial environmental damage.” (54, L35) “In New York State, for example, the bulk storage regulations effectively exclude No. 6 fuel oil and other petroleum products for purposes of regulatory control.” (100) “First, ..., an exclusion should be provided for tanks used to store oils with a pour point greater than 60 degrees Fahrenheit. Such tanks pose little risk to navigable waters because the oil does not flow freely. Moreover, the costs of cleaning and testing such tanks is extremely high because of the difficulty of removing oil from the tank.” (125)

Residual oil. “A ten-year testing cycle is simply not justified for residual oil tanks. Such relatively frequent forced outages will likely impact system reliability in the context of maintaining reserve capacity requirements if, for example, a particular generating unit is supplied from a specific fuel oil tank or an alternative fuel is unavailable.” (100)

Clarification. “‘Integrity testing’ is not defined.” (70)

Frequency of testing.

Construction material or usage. “The requirement of testing every ten years does not take into account construction materials, usage, or many other factors. It is suggested that more flexibility is warranted to address particular cases.” (L30)

Industry standards. “Also, the integrity test interval of 10 years for tanks with containment seems to conflict with API guidance recommending ultrasound thickness measurements within 5 years after commissioning new tanks and at 5 year intervals for existing tanks where the corrosion rate is not know.” (16) “API suggests that adherence to accepted industry operating and inspection standards

should also be accepted in place of the proposed 10 year integrity testing interval. In some cases industry standards provide more specificity, and in others, more stringent requirements than the proposed wording.” (67)

More frequent. The proposed rule “contains too long a period between AST integrity tests (10 years). EPA should develop an AST integrity testing schedule that provides for more frequent testing for older tanks with bottoms made of corrosive material.” (44, 88)

More limited. We should limit the required integrity testing frequency. (71)

Material repairs. “However, to help clarify what constitute material repairs, §112.8(c)(6) should be revised to indicate that such testing must be performed when the repairs involve the installation of a 12 inch or larger nozzle in the shell, a new steel bottom, a door sheet, tombstone replacement in the shell, or other similar repairs that could materially increase the potential for oil to be discharged from the tank.” (83, 102)

Method of testing.

Other techniques. Between hydrostatic testing, we should allow owners or operators to use other inspection techniques while the tanks are in service. This approach would permit owners or operators to schedule tank outages while supporting supply and demand obligations. (25)

Rule list. “Guidelines or recommendations for inspections and testing procedures should be set forth here.” (27) “Unless you are prepared to state what type of ‘integrity testing’ is acceptable to EPA, and to what standards, this paragraph should be deleted.” (121)

Visual inspection.

Internal and external. “The seriousness of certain conditions such as tank bottom settlement, bottom corrosion, or poor condition of roof supports may not be identified by this type of ‘integrity testing’. EPA should consider requiring that integrity testing procedures be complemented with a formal internal visual inspection when the tank is not in service.” (16) “It should be clarified if the extent of a visual inspection would be expected to be both inside and out (that is, product and vapors removed).” (76)

Visual inspections adequate. “We support the need to review the integrity of tanks. We are not in favor of pressure testing and would be concerned with the amount of pressure applied. ... Visual inspection is much more economical and will be used as often as twice yearly where possible. Remote sites would be inspected at least yearly, with full time electronic monitoring used when possible.” (37) “A second exclusion should be provided for tanks that are capable of visible inspection on all sides and utilize secondary containment. In such a case, where

the tank bottom as well as the sides can be adequately inspected, integrity testing is not necessary to maintain the safety of the tanks.” (125) “The Company feels that visually inspecting aboveground tanks fully meets the intent of the testing requirement. During the aforementioned UST rulemaking in 1988, EPA totally exempted USTs which were in basements or vaults if the USTs were totally inspectable for leaks. EPA recognized that these tanks, although they were subterranean, did not require upgrading, release detection, etc., based upon the simple fact that they were inspectable and this was a reliable means of detecting leakage.” (164)

Response: *Support for proposal.* We appreciate commenter support.

Applicability. Integrity testing is essential for all aboveground containers to help prevent discharges. Testing will show whether corrosion has reached a point where repairs or replacement of the container is needed. Prevention of discharges is preferable to cleaning them up afterwards. Therefore, it must apply to large and small containers, containers on and off the ground wherever located, and to containers storing any type of oil. From all of these containers there exists the possibility of discharge.

Air emissions, fatalities. An owner or operator who follows good engineering practice will minimize the possibility of air emissions or fatalities. In any event, an owner or operator must comply with applicable State and Federal clean air and safety requirements.

Ancillary equipment. We agree that integrity testing should include ancillary equipment in some circumstances, and require integrity and leak testing on a periodic basis for valves and piping when a facility lacks secondary containment. 40 CFR 112.7(d). Even with secondary containment, an owner or operator must examine all aboveground valves, piping, and appurtenances regularly to assess the general condition of certain items. 40 CFR 112.8(d)(4). In addition, an owner or operator must conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement. 40 CFR 112.8(d)(4)

Electrical equipment. Because electrical, operating, manufacturing equipment are not bulk storage containers, the requirement is inapplicable to those devices or equipment. 56 FR 54623. See also the definition of *bulk storage container* in §112.2. Furthermore, as noted by commenters, methods may not exist for integrity testing of such devices or equipment.

Hazardous waste. While it is possible that cleaning might generate more hazardous waste, that is not a reason to avoid integrity testing. The purpose of the testing is to prevent container failure leading to a discharge as described in §112.1(b).

Phase-in. We disagree that there should be a phase-in of the requirement because it is already in effect.

Rust. A container with any potential to rust may fail and discharge oil. Further, rust is not the only possible failure factor. For example, integrity testing may reveal an improper weld or inadequate shell thickness before the defect causes a container to fail.

Secondary containment. We disagree that secondary containment for the entire content of a container mitigates the need for integrity testing. Such testing helps prevent the discharge in the first place. Furthermore, oil may escape secondary containment and reach the environment.

Business records. You may use usual and customary business records, at your option, for purposes of integrity testing recordkeeping. Specifically, you may use records maintained under API Standards 653 and 2610 for purposes of this section, if you choose. Other usual and customary business records either existing or to be developed in the future may also suffice. Or, you may elect to keep separate records for SPCC purposes. This section requires you to keep comparison records. Section 112.7(e) requires retention of these records for three years. You should note, however, that certain industry standards (for example, API Standards 570 and 653) may specify that an owner or operator to maintain records for longer than three years.

Frequency of testing, industry standards, 10-year integrity testing. Integrity testing is a necessary component of any good prevention plan. A number of commenters supported a requirement for such testing. It will help to prevent discharges by testing the strength and imperviousness of the container. We agree with commenters that testing according to industry standards is preferable, and thus will maintain the current standard of regularly scheduled testing instead of prescribing a particular period for testing. Industry standards may at times be more specific and more stringent than our proposed rule. For example, API Standard 653 provides specific criteria for internal inspection frequencies based on the calculated corrosion rate, rather than an arbitrary time period. API Standard 653 allows the aboveground storage tank (AST) owner or operator the flexibility to implement a number of options to identify and prevent problems which ultimately lead to a loss of tank integrity. It establishes a minimum and maximum interval between internal inspections. It requires an internal AST inspection when the estimated corrosion rate indicates the bottom will have corroded to 0.1 inches. Certain prevention measures taken to prevent a discharge from the tank bottom may affect this action level (thickness). Once this point has been reached, the owner or operator has to make a decision, depending on the future service and operating environment of the tank, to either replace the whole tank, line the bottom, add cathodic protection, replace the tank bottom with a new bottom, add a release prevention barrier, or some combination of the above.

Another benefit from the use of industry standards is that they specify when and where specific tests may and may not be used. For example, API Standard 653 is very specific as to when radiographic tests may be used and when a full hydrostatic test is required after shell repairs. Depending on shell material toughness and thickness a full hydrotest

is required for certain shell repairs. Allowing a visual inspection in these cases risks a tank failure similar to the 1988 Floreffe, Pennsylvania event. Testing on a “regular schedule” means testing per industry standards or at a frequency sufficient to prevent discharges. Whatever schedule the PE selects must be documented in the Plan.

Integrity testing. “Integrity testing” is any means to measure the strength (structural soundness) of the container shell, bottom, and/or floor to contain oil and may include leak testing to determine whether the container will discharge oil. It includes, but is not limited to, testing foundations and supports of containers. Its scope includes both the inside and outside of the container. It also includes frequent observation of the outside of the container for signs of deterioration, leaks, or accumulation of oil inside diked areas.

Material repairs. The rationale for testing at the time material repairs are conducted is that such repairs could materially increase the potential for oil to be discharged from the tank. Examples of such repairs include removing or replacing the annular plate ring; replacement of the container bottom; jacking of a container shell; installation of a 12-inch or larger nozzle in the shell; a door sheet, tombstone replacement in the shell, or other shell repair; or, such repairs that might materially change the potential for oil to be discharged from the container.

Method of testing. The rule requires visual testing in conjunction with another method of testing, because visual testing alone is normally insufficient to measure the integrity of a container. Visual testing alone might not detect problems which could lead to container failure. For example, studies of the 1988 Ashland oil spill suggest that the tank collapse resulted from a brittle fracture in the shell of the tank. Adequate fracture toughness of the base metal of existing tanks is an important consideration in discharge prevention, especially in cold weather. Although no definitive non-destructive test exists for testing fracture toughness, had the tank been evaluated for brittle fracture, for example under API standard 653, and had the evaluation shown that the tank was at risk for brittle fracture, the owner or operator could have taken measures to repair or modify the tank’s operation to prevent failure.

List of procedures. We disagree that we should state in the rule -- not the preamble -- what integrity testing procedures we consider adequate. We list examples in the rule of possible types of testing, but those are merely examples. While we suggest testing according to industry standards, we realize those standards will not be appropriate for every facility. Where industry standards are inappropriate for a particular facility, the Professional Engineer must devise a standard of testing that is appropriate. We note, however, that a visual inspection must be combined with some other technique.

Pressure testing. We note that we do not require pressure testing.

Routine inspections. We disagree that a routine inspection suffices for an integrity test. A routine inspection may be visual and may not test the tank

sufficiently to meet the §112.8(c)(6) integrity testing requirement. We also disagree that we should require integrity testing only when the inspector thinks there is a risk of discharge because such a standard is entirely subjective.

Visual inspection. For certain smaller shop-built containers in which internal corrosion poses minimal risk of failure; which are inspected at least monthly; and, for which all sides are visible (i.e., the container has no contact with the ground), visual inspection alone might suffice, subject to good engineering practice. In such case the owner or operator must explain in the Plan why visual integrity testing alone is sufficient, and provide equivalent environmental protection. 40 CFR 112.7(a)(2). However, containers which are in contact with the ground must be evaluated for integrity in accordance with industry standards and good engineering practice.

Internal and external. A visual inspection may be either solely external, or external and internal. The rule requires visual testing in conjunction with another method of testing, because visual testing alone is normally insufficient to measure the integrity of a container. Visual testing alone might not detect problems which could lead to container failure.

XI - B(7) Leakage - internal heating coils - §112.8(c)(7)

Background: In 1991, we proposed to redesignate §112.7(e)(2)(vii) of the current rule as §112.8(c)(7). The proposal would require the prevention of leakage through defective internal heating coils. In 1991, we also proposed a new recommendation that the retention systems be designed to hold the contents of an entire tank, be of sufficient size to contain a spill that may occur when the system is not being monitored or observed, or have fail-safe oil leakage detectors.

Comments: *External heating system recommendation.* “It would seem that the cost to install insulation, upgrade boilers, and pay for the extra energy consumption would be outlandish.” (76)

Internal heating coils, opposition to recommendation. “It is felt that aboveground piping can be easily inspected and maintained; and, with drainage at facilities routed to oily water separators or holding ponds, it is unnecessary to have leak proof galleys under aboveground piping. This would be redundant containment and encouraging this installation is economically unjustified.” (25) “The recommendation that aboveground piping be placed into galleys that drain into the oil/water separator is not necessary. Leaks in the aboveground piping can be mitigated through daily inspections and they are often placed within the secondary containment.” (68) Instead of requiring a retention system, which would hold the entire contents of a tank, suggests, “A reasonable alternative would be the installation of an oil/water separator with a high product level indicator; or a flow-stop valve which incorporates a valve that closes if a liquid with a specific gravity of less than 1 is present (such as provided by Enquip of Tulsa).” (76)

Oil/water separators. “In addition, not all facilities have oil/water separators and the same ought not to be a requirement. ... The choice of what type of equipment and requirements an operating facility need should be left to the regulated unit and the qualified independent professional engineer.” (162)

Response: *Alternatives.* The rule does not mandate the use of any specific separation or retention system. Any system that achieves the purpose of the rule is acceptable. That purpose is to prevent discharges as described in §112.1(b) by controlling leakage.

Proposed recommendation. We deleted the proposed recommendation from the rule because we do not wish to confuse the regulated public as to what is mandatory and what is discretionary. We have included only requirements in the rule.

XI - B(8) Good engineering practice - alarm systems - §112.8(c)(8)

Background: In 1991, we proposed to redesignate §112.7(e)(2)(viii) of the current rule as §112.8(c)(8). The provision pertains to engineering requirements formerly labeled “fail-safe.”

Comments: *Support for proposal.* Supports proposed list of devices that we consider to be “fail-safe” engineering. (143)

Terminology. Objects to the term “fail-safe” engineering because nothing is ever fail-safe. Suggests using term “in accordance with good engineering practice” or “consistent with accepted industry practices” instead. (54, 92)

Applicability. “GM recommends that installation of fail-safe equipment be required for storage tanks of volume greater than 100,000 gallons, and/or for storage tanks that were the cause of a reportable spill within the past three years.” (90) “If fail safe devices are appropriate for specific large tanks, the requirement should be phased in over a period of 2 to 5 years.” (116)

Alternatives.

Procedures. Supports use of “procedures” as well as “devices” as good engineering practice measures. (54) Tanks filled “with an operator present should not require such devices.” (116)

UST rules. “With respect to overfill requirements, existing Underground Storage Tank (UST) regulations ... merely require a five (5) gallon overfill bucket - a standard feature for vaulted tanks. Overfill requirements, as contemplated by the proposed revised regulations, should not exceed the EPA standards for USTs.” (50)

Monitoring. “...the ‘fast response system’ for overfill prevention does not provide the same level of protection as a high level alarm or high liquid level pump cutoff. If this

alternative is to be considered further by EPA, the regulations should require that a person be present to monitor gauges and the overall filling of storage tanks.” (111)

Response: *Support for proposal.* We appreciate commenter support.

Terminology. We agree with the commenter that “fail-safe” engineering is inappropriate and have substituted “in accordance with good engineering practice.” The change in terminology does not imply any substantive change in the level of environmental protection required, it is merely editorial.

Applicability. Alarm system devices are necessary for all facilities, large or small, to prevent discharges. Such systems alert the owner or operator to potential container overfills, which are a common cause of discharges. Because this is a requirement in the current rule, no phase-in is necessary.

Alternatives. Under the deviation provision at §112.7(a)(2), you may substitute “procedures” or other measures that provide equivalent environmental protection as any of the alarm systems mandated in the rule if you can explain your reasons for nonconformance. Such procedures might include conformance to UST rules if you can show that such conformance provides equivalent environmental protection to the SPCC requirement.

Monitoring. We agree with the commenter that a person must be present to monitor a fast response system to prevent overfills and have amended the rule accordingly. We disagree that the requirement for alarm devices should not apply when a person is present, because human error, negligence, or inattention may still occur in those cases, necessitating some kind of alarm device.

XI - B(9) Removal of accumulated oil within 72 hours - §112.8(c)(10)

Background: Section 112.7(e)(2)(x) of the current rule requires an owner or operator of an onshore bulk storage facility to promptly correct visible oil leaks that result in a loss of oil from tank seams, gaskets, rivets, and bolts sufficiently large enough to cause the accumulation of oil in diked areas. In 1991, we repropose this requirement in redesignated §112.8(c)(10). We also proposed to require that an owner or operator completely remove accumulated oil or oil-contaminated materials within 72 hours from the time the discharge occurred. We noted that this time frame was consistent with the requirement for diked areas in proposed §112.7(c), where we proposed to require that the entire containment system be impervious to oil for 72 hours.

Comments: *Bioremediation.* “...the 72-hour requirement would effectively limit the choice of cleanup technologies to those that emphasize speed. This would preclude the use of other proven technologies, such as in-situ bioremediation, which cannot be completed in a 72-hour period.” (42, 48, 67, 91, 99, 102, 133, 175, 187). “Bioremediation techniques and other measures which may be used under existing laws are less expensive and create less waste than removal procedures. No materials are

transported, which eliminates the risks inherent in hauling the 'contaminated' dirt. In short, fixing the problem 'on the spot' is often very good advice." (42)

72-hour cleanup standard.

Support for proposal. "As noted in the preamble, such containment would have to be impervious to spilled product for 72 hours." (L17)

Opposition to proposal. We should delete the requirement or change it to a recommendation. (72)

Expensive. "To require total cleanup of spilled oil and material within 72 hours in all cases would be impractical, costly, and impossible in some cases." (22, 37, 72, 90, 99, 170, 187) The 72-hour requirement is excessive and unnecessary because spill response procedures are described in the SPCC Plan. (25) The requirement would be particularly costly for remote facilities. (37)

Health or safety hazard. "Depending on site conditions," 72 hour cleanup "could jeopardize worker safety and health." (48, 67, 91, 102, 170, 175, 187)

Impractical or impossible. "To require total cleanup of spilled oil and material within 72 hours in all cases would be impractical, costly, and impossible in some cases." (22, 48, 57, 72, 83, 92, 98, 102, 107, 125, 143, 153, 170, 175, 184, 189, L2) Removal within 72 hours from the time of the spill would be difficult for unattended facilities. (72) Texas allows on-site soil remediation or treatment. (99) "Frequently it is not technically feasible to remove contaminated soil due to structural concerns or volume considerations. State regulations often will not allow for treatment methods which are commonly employed until a permit has been issued, requiring considerably more time than 72 hours." (153) "The Company agrees that 'accumulated oil' (i.e., free product) be cleaned out of a containment structure, however, 'oil contaminated materials' should not be a concern. This could be construed to mean the walls and floor of a clay dike used for containment." (125,164)

Land disposal problems. "Also, to dispose of a waste sometimes takes as much as two months while waste samples are laboratory tested, arrangements are made with a disposal facility, and State approval is obtained to ship the wastes off site. In many cases, the ideal location to hold the waste until shipment off-site, is within the secondary containment area of the tank which experienced the spill." (92, 125) "To disallow any other method than complete removal of oil contaminated soil from diked areas in these circumstances serves no useful purpose. Moreover, it compounds landfill disposal capacity problems and diverts funds that could be more effectively used to address other more pressing environmental problems." (99, 187)

Low risk, historic spills. “More importantly, at older facilities there may be historically contaminated soil from past spills within diked areas. These soils pose no threat of ‘escape to surface waters. The requirement to clean up in these instances would be prohibitively expensive and would yield no benefit.” (72, 164)

Small spills. “... API believes clarification is needed with regard to cleanup of small discharges as opposed to larger discharges within the proposed 72 hour cleanup period.” (67, 77, 91, 175, 187, L20)

Unnecessary. It is unnecessary to remove all spilled oil within 72 hours if the containment system is designed to be impervious to oil for a longer period of time. (57) Since regulated facilities have secondary containment, discharged oil and oil-contaminated materials would be contained. Therefore, the 72-hour requirement is unnecessary. (107, 189)

Prevention - plastic film. Covering soil with plastic film may be an acceptable method to prevent stormwater contamination during remediation. (99)

Terms to clarify.

Accumulated oil, oil-contaminated materials. We should clarify the terms *accumulated oil* and *oil-contaminated materials*. (57, 62, 125, 153) Asks for clarification of *accumulated oil*, because a slow leak or drip may result in the accumulation of a small puddle of oil in a large containment area with limited access. In this situation, the risk to employees may be greater than the risk to the environment. (62)

Completely removed. We should clarify the term *completely removed*. (57)

Spill event. Our reference to a *spill event* in §112.8(c)(10) is inconsistent with the definition in §112.2(s). (29)

Time calculations. “API notes that the time the spill occurred will not always be known. Therefore, any such requirement should be based on the time the spill is first discovered.” (67, 72, 91, 92, 102, 153, 164, 175)

Clarification needed. Questions how 72-hour period will be calculated. (67, 79, 82, 85, 91, 92, 95, 102, 153, 164, 175)

Time cleanup- alternatives.

Immediately. “Accumulated oil should be cleaned up immediately, and not within the 72 hours proposed.” (27)

72 hours after observation. “GM recommends that accumulated oil of sufficient volume, i.e., greater than 50 gallons, in containment structures should be removed expeditiously but no longer than 72 hours after observation.” (90, 153)

As soon as possible. We should require that the owner or operator complete clean-up operations as soon as “possible” or “practicable,” or “after the spill is discovered.” (48, 67, 83, 91, 102, 133, 143)

Expedientiously. (48, 67, 85, 91, 95, 102, 117, 133, 143)

Initiation within 72 hours. We should amend the proposed requirement to state that clean-up efforts must begin within 72 hours or within a period of time sufficient to permit the clean-up of oil before the containment system begins to leak. (57) “As suggested above, this requirement should be changed to allow that within 72 hours and/or as soon as feasible a spill will be responded to and cleanup initiated in order to ensure that navigable waters are not impacted.” (66, 98, 125, 170, 184, 189, L2, L20) We should require the “prompt removal of precipitation from containment areas” within 72 hours. We should require treatment of the accumulated precipitation from the containment areas, if necessary, within 72 hours after the precipitation had ended. (80)

So as to prevent further environmental impact. “EPA should clarify this requirement to state that ‘accumulated spills should be sufficiently removed within 72 hours so as to prevent further environmental impact.’” (107)

More than 72 hours. “If the spilled oil is contained or controlled or is being remediated, then there should be additional time given for the response measures in process, especially if there are difficulties encountered in the cleanup.” (22) “Nor is it necessary to remove all spilled oil within seventy-two hours if the containment system is designed to be impervious to oil for a much longer period of time.” (57, 66, 98, 125, 170, 184, 189, L2)

96 hours. “A 96 hour time frame would still meet the general intent of the rule by allowing unattended weekend operation, but still provide adequate response time once the event is discovered without putting the facility in jeopardy of not complying with the regulations.” (87)

144 hours, at least. “Alyeska recommends that EPA at least double this time requirement.” (77)

Response: *Support for proposal.* We appreciate commenter support.

Applicability. The requirement to clean up accumulations of oil is applicable to all facilities, large and small. The size of the accumulation is irrelevant, as any accumulation may migrate to navigable waters or adjoining shorelines. The damage to the environment may be the same, depending on the amount discharged.

72-hour cleanup standard. We have deleted the proposed 72-hour cleanup standard because it would preclude bioremediation. We also agree that under certain circumstances, such a time limit might jeopardize worker safety and health. Therefore, we have maintained the current standard that visible discharges must be promptly removed. *Prompt* removal means beginning the clean-up immediately after discovery of the discharge, or immediately after taking any action to prevent fire and explosion or other threats to worker health and safety. However, actions to prevent threats of fire or explosions may not be used to unreasonably delay such efforts. The size of the accumulation is irrelevant, as any accumulation may migrate to navigable waters or adjoining shorelines.

Extent of and methods of cleanup. No matter what method of clean-up method you use, you must completely remove the accumulated oil. Any effective method that complies with all other applicable laws and regulations is acceptable. Bioremediation may be one acceptable method of clean-up. Acceptable methods will depend on the weather, other environmental conditions, and good engineering practice. If the clean-up method chosen undermines the stability of a dike, the owner or operator must repair the dike to its previous condition.

Prevention - plastic film. We support all efforts to prevent contamination of navigable waters. An owner or operator may choose to spread plastic film over the diked area to prevent stormwater contamination, or use some other acceptable method. However, the owner or operator must dispose of the film properly if he chooses that method.

Terms to clarify.

Accumulated oil, oil-contaminated materials. An “accumulation of oil” means a discharge that causes a film or sheen or a sludge or emulsion in a diked area. See 40 CFR 110.3(b). The term “oil-contaminated materials” is not used in the final rule, because oil must accumulate on something such as materials or soil. Therefore, the term is redundant. Instead, in the final rule we use the term “accumulation of oil”, which includes anything on which the oil gathers or amasses within the diked area. Such accumulation may include oil-contaminated soil or any other oil-contaminated material within the diked area that impairs (i.e., decreases the capacity of) the secondary containment system.

Completely removed. We no longer use the term “completely removed” in §112.8(c)(10). The requirement to remove any accumulation of oil means clean-up of all such accumulations.

Spill event. We have removed the term “spill event” from the proposed paragraph and note that we agree with the commenter who noted that the reference to a “spill event,” or a “discharge as described in §112.1(b),” within a diked area is inconsistent with that concept.

XI - B(10) Mobile and portable containers - §112.8(c)(11)

Background: Under §112.7(e)(2)(xi) of the current rule, an owner or operator must locate mobile or portable containers so as to prevent spilled oil from reaching navigable waters. He must provide secondary containment for the largest single compartment or tank. He must locate his facility where it will not be subject to periodic flooding or washout. In 1991, we proposed to designate §112.7(e)(2)(xi) of the current rule as §112.8(c)(11), and to change the requirement for secondary containment to a recommendation. We also proposed to recommend, not require, that an owner or operator locate a mobile or portable oil storage container in an area not subject to periodic flooding or washout.

Comments: *Floods.* "...portable tanks are not the only tanks which should be kept out of the flood plain. The recommendation should be extended to all new equipment." (111)

Requirement or recommendation. "Tanks should be required to be located in areas not subject to flooding." (27) We should amend the rule to require locating mobile or portable containers to "prevent discharges from entering *navigable waters*." (67)

Secondary containment - requirement or recommendation.

Recommendation. We should place the secondary containment recommendation in another document. (121) "Secondary containment for mobile or portable tanks should be left as a recommendation. In addition, some basic security procedures and a contingency plan may be adequate for spill prevention and control from mobile and portable tanks. Further investigation into the spill history from these types of tanks should be conducted to assess the environmental threat from such tanks." (190)

Time limits. "Mobile and portable tanks should be defined more clearly. Ohio EPA recommends defining such a tank as one which is in place on a contiguous property for 10 days or less." (27)

Response: *Floods.* We deleted the proposed recommendation on siting of mobile containers in this rule because we do not wish to confuse the regulated public over what is mandatory and what is discretionary. These rules contain only mandatory requirements.

Requirement or recommendation. We agree that the purpose of the rule is to prevent discharges from becoming discharges as described in §112.1(b). Therefore, in response to comment, we have modified the proposed rule to require positioning or locating mobile or portable containers to prevent "a discharge as described in §112.1(b)," rather than "oil discharges." "A discharge as described in §112.1(b)" is a more inclusive term, tracking the expanded scope of the amended CWA.

Secondary containment. In response to comments, we have maintained the secondary containment requirement in the current rule because secondary containment is necessary for mobile containers for the same reason that it is necessary for fixed containers; to prevent discharges from becoming discharges as described in §112.1(b). Secondary containment must also be designed so that there is ample freeboard for anticipated precipitation. We have therefore amended the rule on the suggestion of a commenter to provide for freeboard. We agree with the commenter that the amount of freeboard should be sufficient to contain a 25-year storm event, but are not adopting that standard because of the difficulty and expense for some facilities in securing recent information concerning 25-year, 24-hour storm events at this time. Should that situation change, we will reconsider proposing such a standard in rule text. Freeboard sufficient to contain precipitation is freeboard according to industry standards, or in an amount that will avert a discharge as described in §112.1(b). Should secondary containment not be practicable, you may be able to deviate from the requirement under §112.7(d).

We clarify that the secondary containment requirement relates to the capacity of the largest single compartment or container. Permanently manifolded tanks are tanks that are designed, installed, or operated in such a manner that the multiple containers function as a single storage unit. Containers that are permanently manifolded together may count as the “largest single compartment,” as referenced in the rule.

Time limits. We decline to place a time limitation in a definition of mobile or portable containers. Mobile or portable containers may be in place for more than ten days and still be mobile. Mobile containers that are in place for less than 10 days may still experience a discharge as described in §112.1(b).

XI - C: Facility transfer operations, pumping, and facility process - §112.8(d)

XI - C(1) Buried piping - protective coatings and cathodic protection - §112.8(d)(1)

Background: Section 112.7(e)(3)(i) of the current rule requires an owner or operator to cathodically protect and provide protective wrapping and coating on *all* buried piping installations if soil conditions warrant. In 1991, we proposed to redesignate §112.7(e)(3)(i) as §112.8(d)(1). In that proposal we recommended that an owner or operator place all piping installations aboveground, where possible. We also proposed to require that an owner or operator cathodically protect and provide protective wrapping and coating on *new or replaced* buried piping, with an alternative option to comply with other corrosion protection standards for buried piping in 40 CFR part 280, the underground storage tank (UST) regulation.

We proposed to continue to require that an owner or operator carefully inspect buried pipeline for deterioration if a pipeline section is exposed for any reason. We proposed that if an owner or operator finds corrosion damage, he must inspect the damage and take corrective action as indicated by the magnitude of damage.

Finally, in the preamble, we encouraged owners or operators to place piping installations in leak-proof galleys that feed into the facility's oil/water separator. We also proposed to recommend that buried piping installations comply to the extent applicable with all of the relevant part 280 provisions.

Comments: *Aboveground piping recommendation.*

Support for recommendation.

All piping. Owners or operators should place all piping aboveground to help detect piping system problems before there is a discharge. (L1)

New piping. We should revise §112.8(d)(1) to recommend that owners or operators place all *new* piping aboveground, where *appropriate*. It would be “onerous, costly, and not necessarily protective of navigable waters” to move all existing buried lines aboveground. (67)

Editorial suggestion. “The first sentence in proposed 40 CFR 112.8(d)(1) should be properly reworded (i.e., remove ‘shall’ to read, ‘It is recommended that all piping be placed aboveground, where possible.” (79, 102)

Opposition to recommendation. The recommendation is “a clear safety problem if followed as recommended by the agency. ... Above ground installations do not provide the requisite degree of worker safety, because of the tripping hazard, that Delhi seeks to attain.” (34)

Buried piping recommendation - part 280.

Support for requirement. The rule should “require – rather than recommend, that buried piping comply with the corrosion protection provisions of 40 CFR part 280.” (44, 121)

Recommendations not followed. “Also, practices for integrity testing and for installation of pipes pursuant to 40 CFR 280 should be changed from ‘recommended’ practices to ‘required’ practices. Our experience is that recommendations without standards are not usually followed.” (111)

Corrosion protection.

Support for proposal. Applying protective coating and cathodic protection on buried piping provides sufficient leak protection. (34) We cannot enforce the current requirement for protecting buried piping installations “if soil conditions warrant.” (121) “MDE strongly supports amendments to” §112.8(d)(1). (135, L17)

Opposition to proposal.

Coating only. “New and replacement piping should include protective coating. Cathodic protection should be required only when soil conditions require it. Tests to determine the need for cathodic protection are very specific and should be used to identify those locations requiring the protection.” (114)

Ineffective. “Protective coating and cathodic protection will not prevent a discharge of oil to the environment in the event of a pipe fracture, nor will such protection be able to detect a leak if one occurs. The practice of using double walled pipe or secondary containment and product sensitivity leak detection for new installations is currently required by NJDEPE.” (147)

Keep current rule. An owner or operator should protect new buried piping “where soil conditions support the operation of a corrosion system and where there is a history of external buried piping corrosion that can be controlled by corrosion protection.” (67, 85, 114, 143)

Repairs. “EPA should clarify that only the section of the line undergoing repair must be retrofitted with this corrosion protection.” It would be very costly to retrofit the entire line. (83, 88, 102)

Coating only on replaced sections. “Placing cathodic protection on sections of replaced piping is unwieldy and not technically feasible because the cathodic protection requires considerable maintenance. Bethlehem endorses the use of cathodic protection when an entire pipeline is replaced and protective wrapping on all replaced sections of pipe.” (88)

Leak-proof galleys. Our recommendation for owners or operators to install leak-proof galleys under aboveground piping is redundant and economically unjustifiable, because owners or operators easily can inspect and maintain aboveground piping, and because aboveground piping is often placed within secondary containment that drains to oil/water separators. (25, 68)

Response: *Support for proposal.* We appreciate commenter support.

Aboveground piping recommendation. While we have deleted the proposed recommendation from the rule text because we do not wish to confuse the regulated public over what is mandatory and what is discretionary, we still believe that piping should be placed aboveground whenever possible because such placement makes it easier to detect discharges. The decision to place piping aboveground might include consideration of safety and traffic factors.

Buried piping recommendation - part 280. We have deleted the recommendation from the proposed rule that all buried piping installations comply to the extent practicable with 40 CFR part 280, because we are excluding recommendations from this rule to avoid confusion with what is mandatory and what is discretionary. Also, some buried piping

now subject to part 112 will be subject only to 40 CFR part 280 or a State program approved under 40 CFR part 281 under this rule. See §112.1(d)(4).

Corrosion protection. Based on EPA experience, we believe that all soil conditions warrant protection of new and replaced buried piping. EPA's cause of release study indicates that the operational piping portion of an underground storage tank system is twice as likely as the tank portion to be the source of a discharge. Piping failures are caused equally by poor workmanship and corrosion. Metal areas made active by threading have a high propensity to corrode if not coated and cathodically protected. See 53 FR 37082, 37127, September 23, 1988; and "Causes of Release from US Systems," September 1987, EPA 510-R-92-702. If you decide to deviate from the requirement, for example, to provide an alternate means of protection other than coating or cathodic protection, you may do so, but must explain your reasons for nonconformance, and demonstrate that you are providing equivalent environmental protection. A deviation which seeks to avoid coating or cathodic protection, or some alternate means of buried piping protection, on the grounds that the soil is somehow incompatible with such measure(s), will not be acceptable to EPA.

A "new" or "replaced" buried piping installation is one that is installed 30 days or more after the date of publication of this rule in the Federal Register. We have deleted the words "new" and "replaced" from the proposed language and substituted this specific date so the effective date is clearer to the regulated community. Under the current rule, you have an obligation to provide buried piping installations with protective wrapping and coating only if soil conditions warrant such measures. Under the revised rule, you must provide such wrapping and coating for new or replaced buried piping installations regardless of soil conditions.

You should consult a corrosion professional before design, installation, or repair of any corrosion protection system. Any corrosion protection you provide should be installed according to relevant industry standards. When piping is replaced, you must protect from corrosion only the replaced section, although protection of the entire line whenever possible is preferable. Equipping only a small portion of piping with corrosion protection may accelerate corrosion rates on connected unprotected piping. While we agree that corrosion protection might not prevent all discharges from buried piping, it is an important measure because it will help to prevent most discharges.

We disagree that we should require *only* protective coating and not cathodic protection. Protective coating and wrapping *and* cathodic protection provide the maximum feasible leak prevention technology.

We note that no strategy can prevent all discharges from buried piping, but corrosion protection and coating will help prevent most discharges.

Double-walled piping. Double-walled piping or secondary containment or sensitive leak detection for buried piping may be acceptable as a deviation from the requirements of this paragraph under §112.7(a)(2) if you explain your reasons for nonconformance with

the requirement and show that the means you selected provides equivalent environmental protection to the requirement. However, we will not require such measures because we did not propose them.

Leak-proof galleys. We have not included such a recommendation in the final rule, because all final rule provisions are mandatory.

XI - C(2) Terminal connections - §112.8(d)(2)

Background: Section 112.7(e)(3)(ii) of the current rule requires an owner or operator to cap or blank-flange an oil pipeline terminal connection when it is not in service or is in standby service for an extended time. In 1991, we proposed to redesignate §112.7(e)(3)(ii) as §112.8(d)(2), and to clarify that “an extended time” is “six months or more.”

Comments: *Support for proposal.* “Consistency for determining when loading/unloading connections must be securely capped or blank-flanged will be promoted by specifying what constitutes ‘an extended time’, and NJDEPE supports the specified time period of six months.” (147)

Opposition to proposal. The rule should be rewritten as follows: “When piping is not in service or *is not* in standby service....” “Typically piping that is in standby service is only needed in emergency situations or when there is an operational problem. ... It is not appropriate for this requirement to apply to standby piping, especially if the piping must be put into service quickly during an emergency to insure the safe operation of the facility.” (67, 102)

Response: We appreciate commenter support. We have decided to keep the current standard of requiring capping or blank-flanging terminal connections when such piping is not in service or is in standby for an extended time in order to maintain flexibility for variable facilities and engineering conditions. We define “an extended time” in reference to industry standards or at a frequency sufficient to prevent discharges. We disagree with commenters that the requirement should not apply to piping that is not in standby service because some discharges may be caused by loading or unloading oil through the wrong piping or turning the wrong valve when the piping in question was actually out-of-service. Typically, piping that is in standby service is only needed in emergency situations or when there is an operational problem. In the rare situations when such piping is needed immediately, the owner or operator may remove the cap or blank-flange to return the piping to service.

XI - C(3) Aboveground valves and piping; buried piping - §112.8(d)(4).

XI - C(3)-1 Inspection of aboveground valves, piping, and appurtenances

Background: Under §112.7(e)(3)(iv) of the current rule (redesignated in the final rule as §112.8(d)(4)), an owner or operator must regularly inspect all aboveground valves and

pipelines. Operating personnel must assess the general conditions of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locked valves, and metal surfaces. In 1991, we proposed that examinations of aboveground valves and piping must be monthly, and must include appurtenances.

In 1991, we recommended in §112.8(d)(4) that all valves, pipes, and appurtenances conform to relevant industry codes, such as ASME standards.

Comments: *Applicability.*

Electrical equipment. “This requirement would impose an extremely heavy burden on the electric utility industry if maintained in the final rule. The utility industry has millions of pieces of equipment in tens of thousands of facilities that could be subject to the SPCC requirements, some in remote areas. It would be extremely time-consuming and expensive to require that each of these be inspected monthly.” (125)

Large facilities. We should exempt from the monthly examination requirement, piping systems associated with large tanks with a storage capacity greater than 100,000 gallons. (90)

Buried piping recommendation.

Support for recommendation. “ACMS agrees that all buried piping should be tested as proposed.” (51, 87, 107, 168)

Requirement instead. “ATA believes that such testing is reasonable and in accordance with good engineering practices. In order to provide sufficient environmental protection and to minimize industry remediation costs, such testing should be required rather than recommended. Also, it should apply to all SPCC-regulated facilities, not only large facilities (greater than 42,000 gallons) as EPA has suggested.” (87, 107, 168)

Editorial suggestion. “All aboveground valves, piping and appurtenances in oil service should be visually inspected regularly, monthly or more frequently if necessary, and they shall be subject to an annual examination where possible.” (143)

Industry standards recommendation. “Similarly, proposed section 112.8(d)(4) should require, rather than recommend, that all valves, pipes, and appurtenances conform to relevant industry codes.” (44) “This is also the place to require that piping and fittings be manufactured and assembled to industry codes (which need to be listed) for all construction beginning after the effective date of this part.” (121)

Methods of inspection.

Pressure testing. “We agree that monthly visual examinations of aboveground piping may be sufficient. However, a more sophisticated method of heating should be required every three or four years, such as pressure testing.” (27)

Visual examinations. We should require periodic visual examinations “in accordance with accepted industry standards.” (67, 83, 91, 102)

Monthly inspection.

Support for proposal. Support for the §112.8(d)(4) proposed requirement for *monthly* examinations of aboveground valves, piping, and appurtenances. (27, 91)

Large and small facilities. Our proposed monthly examination should be a requirement for large facilities, but a recommendation for small facilities. (135)

Opposition to proposal.

Costly. Monthly examinations require large facilities to commit financial and personnel resources. (77) Monthly examinations are too restrictive (155). Unjustified and expensive. (L30)

Difficult. “GM believes that all aboveground valves, piping, and appurtenances should not be subject to mandatory monthly examinations GM believes that the owner should be provided the flexibility to periodically examine piping systems at a necessary frequency to insure leaks and failure conditions are not occurring. Failure of aboveground piping system are unlike underground systems where corrosion is the main cause. Aboveground piping and appurtenances failure are more often caused by accidental damage or vibrational fatigue.” (90)

Recommendation instead. “The Agency has not shown that this requirement is necessary to reduce any risk of discharge to navigable waters, and therefore this provision should remain as a ‘should’ to allow for the exercise of good engineering practice.” (125, 136, 143, 155, 189) “We suggest that proposed §§112.8(d)(4) and (d)(5) be recommendations instead of requirements for facilities that store more than 42,000 gallons.” (39)

Unnecessary. We should delete the §112.8(d) requirements since they are unnecessary. They are unduly onerous, since discharges emanating during transfer operations would be properly contained according to the SPCC Plan for that facility. Monthly examinations are excessive, unnecessary, and expensive. (189, L30)

Alternatives to monthly testing.

Every six months. “A six month examination period combined with an obligation by the operator to be alert for spills that could result from failure of pipes and appurtenances is a more reasonable and economic approach.” (77)

Owner/operator discretion. The owner or operator should determine examination frequency. (90, 155)

Quarterly. Examinations should be performed quarterly - not monthly - for exploration and production facilities. (114) “Large facilities can have thousands of valves and miles of pipe, and even visual inspections would be very time-consuming and costly. Further, there is some question as to whether monthly inspections are warranted; the condition of piping and valves rarely changes significantly in one month.” (175)

System examinations. We should not require monthly examinations, but should require systems examinations with sufficient frequency to assure safe and proper maintenance and operations. (184)

Clarification needed. We did not explain what the monthly aboveground examination would require. (77)

Response: *Support for proposal.* We appreciate commenter support.

Applicability. Inspection of aboveground valves, piping, and appurtenances must be a requirement to help prevent discharges. Such valves, piping, and appurtenances often are located outside of secondary containment systems, and often do not have double-wall protection or some form of secondary containment themselves. Therefore, any discharge from such valves, piping, and appurtenances is more likely to become a discharge as described in §112.1(b). Examination of discharge reports from the Emergency Response Notification System (ERNS) show that discharges from such valves, piping, and appurtenances are much more common than catastrophic tank failure or discharges from tanks.

Electrical equipment. The requirements of this paragraph do not apply to electrical utilities and other facilities with oil-filled equipment because they are not bulk storage facilities.

Exploration and production facilities. Regarding the comment that we should require inspections less frequently for exploration and production facilities, the point is moot. Section 112.8 excludes production facilities from its scope.

Large facilities. The requirement must be applicable to large and small facilities covered by this section, because of the same threat of discharge.

Editorial suggestion. We agree with a commenter that the rule applies only to “oil-handling” piping and valves, not all such piping and valves, which may be unrelated to oil activities. However, no change in rule text is necessary because the entire rule

applies only to procedures, methods, or equipment that are involved with the storage or use of oil.

Industry standards recommendation. We deleted from rule text the recommendation that all valves, pipes, and appurtenances conform to industry standards, because we do not wish to confuse the public with discretionary items in a mandatory rule, but we endorse its substance. However, we do endorse conforming with industry standards and codes because such conformance reflects the exercise of good engineering practice.

Monthly inspection. The final rule maintains the current standard of “regular” inspections, on the suggestion of commenters who noted that at some remote sites monthly inspections are impractical, especially in harsh weather conditions. Furthermore, we agree with commenters that “regular” inspections are inspections conducted “in accordance with accepted industry standards,” rather than the monthly proposed standard. You must include appurtenances in the inspection. Inspections may be either visual or by other means, including pressure testing. However, we do not require pressure testing or any other specific method. We agree that, subject to good engineering practice, pressure testing every three or four years may be warranted in addition to regular inspection of aboveground valves, piping, and appurtenances. However, we believe that regular inspection is sufficient to help prevent discharges and will not impose any additional requirements at this time.

Aboveground leaks. In response to the comment that leaks from aboveground piping are discovered more quickly than from underground storage tanks, we note that leakage may occur from any piping. An owner or operator must inspect aboveground valves, piping, and appurtenances to prevent such leakage.

Integrity testing. In response to the comment that *integrity testing* is impractical for piping systems associated with storage tanks designed to operate as a gravity system, we note that we did not propose testing of aboveground piping. In response to the comment that accidental damage or vibrational fatigue most often causes aboveground system failure, we note that these conditions may become apparent when the owner or operator inspects the general conditions of aboveground valves, piping, and appurtenances.

Transfer operations. In response to the comment that changes emanating during transfer operations would be properly contained according to the SPCC Plan for that facility, we think this remark is unrelated to the utility of preventive testing and remediation. Proper containment is an effective control measure for an actual discharge.

Visual inspections. Inspections may be either visual or by other means, including pressure testing. However, we do not require pressure testing or any other specific method. We think the inspection method is best left to good engineering practice.

XI - C(3)-2 Integrity and leak testing of buried piping - §112.8(d)(4)

Background: Under current rule §112.7(e)(3)(iv), an owner or operator must conduct periodic pressure testing for piping in areas where facility drainage is such that a failure might lead to a spill event. In 1991, we proposed to redesignate §112.7(e)(3)(iv) as §112.8(d)(4), and to delete the periodic pressure testing requirement from the rule. Instead, we proposed to recommend annual integrity and leak testing or monthly monitoring of buried piping following the requirements of 40 CFR part 280, the Underground Storage Tank (UST) regulations. We proposed to require that an owner or operator maintain testing or monitoring records for five years.

Comments: *Applicability.*

Double-walled tanks and piping. The configuration of a vaulted tank is unsuitable for monthly examinations we proposed. “VAST (Vaulted aboveground storage tank) technology also requires that all fittings and pipes come out of the top of the tank, which eliminates the possibility of leaking from the valves, pipes, or fittings and significantly reduces the potential for corrosion.” (65) Exterior tanks and piping systems in remote locations are secondarily contained and have low-level alarms connected to an attended facility. (79) “An alternative would be to allow double walled underground piping or other means of secondary containment for the pipe itself to be exempt from annual testing requirements. This type of piping is one way of addressing providing secondary containment to meet RCRA standards.” (87)

Manned facilities, aboveground facilities, cathodically protected facilities. “...discretion should be applied to and exceptions from periodic buried pipe testing should be established for manned facilities, aboveground facilities, and cathodically protected facilities.” (192)

Support for recommendation. “This provides for maximum flexibility in the use of good engineering practices.” (39, 48, 66, 72, 95, 102, 103, 116, 150, 161, 175, 188, 192, L8, L29)

Alternatives.

3 years. “Oxychem recommends integrity testing be required on underground piping every three years, unless failure data supports more frequent testing.” (141)

3-4 years. “However, a more sophisticated method of heating should be required every three to four years, such as pressure testing. ... Frequency may be based on aquifer use.” (27)

5 years. “The testing for underground piping should be conducted once every five years. This would be consistent with the requirements for aboveground piping systems.” (L2, L20)

Owner/operator discretion. “Integrity testing of buried tanks, piping and valves should be discretionary in all cases. Cites pollution risk of testing. (102, 136, 155, 175)

Periodic testing. We could make part 112 more cost-effective by requiring "periodic testing of existing piping under a reasonable compliance schedule" to provide additional safeguards without the risks and difficulties the proposed recommendation presented. (L35)

Regular basis. We should require testing on a regular basis. (143)

Small facilities. We should allow owners or operators of small facilities with secondary containment to use good engineering practice to determine the testing frequency. (10) We should allow small facilities the discretion to determine testing frequency, but require owners or operators of large facilities to conduct the monthly monitoring. (116, 182)

When a line is exposed. “API believes that buried piping should be inspected for corrosion and necessary remedial action whenever a section of the line is exposed.” (67, 91, L30)

Opposition to recommendation.

Costly. “It would be impractical and extremely costly for small facilities to implement the recommended integrity and leak testing.” (34, 66, 115) Annual testing would interfere with essential facility operations. (77) The need to monitor buried piping systems monthly is costly and a significant administrative burden. (90, 188)

Drawbacks. “There are a variety of drawbacks with performing pressure testing of piping systems more frequently than site-specific conditions indicate are necessary. Pressure testing of such systems often results in the generation of waste materials and air emissions that otherwise would not have resulted.” (102) “Performing annual integrity testing of pipes and valves could be detrimental to the life expectancy of the piping. When a hydrostatic integrity test is performed, the piping is often subjected to 1.5 times its design pressure. Annual testing will very likely cause undue stress on the piping and can potentially lead to premature failure, and consequently, releases to the environment.” (141, 175)

Impractical for multiple sites. “However, monthly testing is not practical at the many sites we have, especially those sites which are not accessible in the winter. Our fuel piping is contained within a secondary enclosure. If a leak occurs, the product will be contained and drained into a containment area where it will be noticed. The tank system has been designed to prevent any contamination to the environment if a failure should occur.” (37, 79)

Inaccurate predictor. “Additionally, all the test would show is that the piping is not leaking at that particular moment. It would not be an accurate predictor of the future integrity of the line.” (34, 115)

Non-operational pipelines. “Similarly, the pipeline integrity testing program would be too onerous to impose on historic, non-operational buried pipelines, the location of which are not know.” (35)

Other leak prevention instrumentation. “Requiring annual tests on buried piping would severely limit the facility’s ability to receive feedstocks and deliver finished products. It should not be necessary for these proposed requirements taking into consideration the other leak prevention instrumentation that would sound alarms, shut off pumps, and automatically close valves to isolate sections of piping.” (25)

Piping age, size. “Integrity testing of underground pipes on an annual basis appears too stringent and should be scheduled to account for the age of the facility (as is the case of UST regulations.)” We should require “testing for buried piping on a schedule related to the age and size of the system, with greater frequencies for older and larger systems.” (89, 95, 102, 197, L30) (L30)

Requirement instead. “Annual integrity and leak testing of buried piping will not be conducted unless it is made a requirements.” (27, 44, 51, 87, 107, 111, 168) “Additionally, given the relatively higher frequency of piping leaks compared to tank leaks, it is essential that facility owners or operators be required to conduct ‘annual integrity and leak testing of buried piping or monitor buried piping on a monthly basis, ..., a requirement similar to that in 40 CFR part 280.’” (44) We should change the proposed §112.8(d)(4) recommendation to a requirement or delete it. (121) “Proposed 112.8(d)(4) should be a requirement since piping often runs outside of secondary containment systems. Examination of ERNS data will reveal that spills from piping are much more common than catastrophic tank failures or leaks from tanks. Buried piping is not capable of being visually inspected on a periodic basis, and many facilities do conduct integrity or leak testing of buried piping on a regular basis.” (168) “Because secondary containment would not affect underground spill pathways, annual testing should be required of all underground piping systems.” (L1)

Large facilities. “We agree with the SPCC Task Force that such provisions should be made mandatory for large facilities. Buried piping which is unprotected should be inspected annually regardless of facility size.” (L17)

Too restrictive. The proposed testing provision is too restrictive. (155)

Coast Guard rules. The buried piping recommendation should be consistent with U.S. Coast Guard rules for testing piping. (143)

Length and nature of piping. It is impractical to conduct monthly monitoring of lengthy buried piping systems. (66) “UCC believes that this should not apply to piping less than ten feet or piping which conveys limited flow annually.” (190)

Methods of testing.

Guidance needed. We did not provide guidance on the types of accepted integrity testing or define what constitutes a *leak rate*. (66, 80)

Hydrostatic testing. Hydrostatic testing should include testing with the product and gases to achieve the required pressure. (143)

Part 280. Part 280 test methods and monitoring techniques do not apply to all buried piping systems, such as large diameter piping, booster pumps, and valves and connections. (66) “Alyeska also is confused by the preamble’s statement that integrity and leak testing follow 40 CFR part 280. However, there is no mention of 40 CFR part 280 in the proposed rule for integrity and leak testing.” (77)

Visual or hydrostatic testing adequate. “A more reasonable requirement would be to require annual integrity testing of buried piping. Further, a requirement that such testing be anything other than visual or hydrostatic is financially burdensome, and also costly in terms of manpower.” (188, L18, L30)

Oil-handling piping. We should clarify that our proposed integrity and leak testing or monthly monitoring recommendation applies only to oil-handling piping and equipment - not *all* buried piping or other equipment unrelated to oil operations. (103)

Recordkeeping.

Opposes proposal. We should exempt ASTs from the recordkeeping requirement. (65) It is unreasonable to require a facility to keep records of a recommended practice (77). The recordkeeping requirement is costly and a significant administrative burden. (90) The five-year recordkeeping requirement is overly burdensome and unnecessary. (189) The proposed requirement is unmanageable and we failed to show that it is necessary to reduce any reasonable risk of discharge to navigable waters. (125)

Supports proposal. Supports the proposed requirement that an owner or operator maintain testing and monitoring records for five years. (L1)

Separate document for recommendations. We should keep discretionary provisions in a separate guidance document. (27)

Response: *Support for proposal.* We appreciate commenter support.

Buried piping. We have deleted the text of the proposed recommendation to conduct annual integrity and leak testing of buried piping or monitor buried piping on a monthly basis from the rule because we do not wish to confuse the regulated public over what is mandatory and what is discretionary. This rule contains only mandatory requirements. However, we continue to endorse the recommendation as a discretionary action, and suggest that you conduct such testing according to industry standards.

We agree with a commenter that the proposed recommendation would apply only to “oil-handling” piping and valves, not all such piping and valves, which may be unrelated to oil activities. However, no change in rule text is necessary because the entire rule applies only to procedures, methods, or equipment that are involved with the storage or use of oil. In response to the commenter who urged that the proposed recommendation not apply to buried piping of less than 10 feet in length, we believe that any buried piping, regardless of length, may cause a discharge, and therefore should be tested. Double-walled piping might be an acceptable alternative to integrity and leak testing or monthly monitoring. If you choose double-walled piping as an alternative, you must explain your nonconformance with the rule requirements, and explain how double-walled piping provides equivalent environmental protection. See 112.7(a)(2).

On the suggestion of commenters, we have modified the proposed recommendation for annual testing or monthly monitoring of buried piping into a requirement that you must only conduct integrity and leak testing of such piping at the time of installation, modification, construction, relocation, or replacement. We believe that when piping is exposed for any reason, integrity and leak testing of such exposed piping according to industry standards is appropriate because piping is visible at that point, and testing is easier because the piping is more accessible. The same commenters also recommended that unprotected underground piping be subject to engineering evaluations every five years, but we recommend such evaluations be conducted in accordance with industry standards to preserve flexibility in case the time frame changes with changing technology.

Double-walled or vaulted tanks. If you have vaulted containers, the requirement for integrity and leak testing of buried piping might be the subject of a deviation under §112.7(a)(2) if those pipes, valves, and fittings come out of the top of the container and are not buried, or are encased in a double-walled piping system and you thereby significantly reduce the potential for corrosion.

Feedstocks. We disagree that buried piping testing, whether annual or otherwise, would limit the facility’s ability to receive feedstocks and deliver finished products. The facility may schedule testing so as not to interfere with receipt of products.

Large or small facilities. This requirement applies to facilities of any size because the risk of discharge is the same.

Manned facilities, aboveground facilities, cathodically protected facilities. The requirement for integrity and leak testing applies only to buried piping. Therefore, aboveground piping, whether manned or not, is exempted. Piping cathodically

protected is likewise not exempt, but may be the subject for a deviation if you explain your reasons for nonconformance, and show that cathodic protection provides equivalent environmental protection to the requirement to conduct integrity and leak testing of buried piping when it is installed, modified, constructed, relocated, or replaced.

Piping material or age. Good engineering practice would include consideration of these factors, as well as site conditions.

Coast Guard rules. We disagree that our rules should necessarily be consistent with Coast Guard rules on buried piping testing. We regulate non-transportation-related facilities. Comparing these facilities with transportation-related facilities under Coast Guard programs is inappropriate because of the differences in the types of facilities that EPA regulates.

Cost. We disagree integrity and leak testing is burdensome or costly for small facilities, or that testing other than visual or hydrostatic testing is financially burdensome and costly in terms of manpower. We do not specify the method of such testing. You may use the least costly method that meets the requirements of the rule.

Method of testing. We do not require pressure testing or any other specific method. While testing pursuant to standards following part 280 or a state program approved under part 281 is certainly acceptable, it is not required. Generally we recommend testing according to industry standards.

Guidance. We suggest use of industry standards where appropriate.

Recordkeeping. We agree that a five year period for recordkeeping is more than necessary, and instead require that records be kept for a maximum of three years. See §112.7(e). We disagree that ASTs should be exempt from the recordkeeping requirement. There is no deviation for recordkeeping if a requirement to keep records is applicable. If the owner or operator of a vaulted tank deviates from the requirement to test buried piping at the specified intervals, he must explain his reasons for nonconformance, and provide equivalent environmental protection. If the equivalent environmental protection provided requires tests or inspections, records of those tests or inspections must be maintained for three years.

XI - C(4) Vehicular traffic - §112.8(d)(5)

Background: Section 112.7(e)(3)(v) of the current rule requires warning verbally or by appropriate signs for vehicular traffic granted entry into the facility to be sure that the vehicle, because of its size, will not endanger aboveground piping. In 1991, we proposed to redesignate the provision as §112.8(d)(5), adding a recommendation that the owner or operator post weight restrictions, as applicable, to prevent damage to underground piping.

Comments: *Support for proposal.* “It seems that good engineering practices would exclude heavy equipment from crossing buried piping which does not have adequate cover to protect the pipe.” (39, 48, 51, 53, 72, 102, 143, 147, 161, 168, L8).

Alternatives.

Additional structural protection. “MDE recommends that if a buried pipe must be placed across a thoroughfare, it should be installed with additional structural protection. Proper installation is preventative and is a better alternative over a sign. The vehicle weight restriction signs are not always needed.” (135)

Local building codes. “In virtually all cases, local building codes or other standards already address the issue of buried piping protection.” (53)

Location and marking. “This could result in weight limits being set low at some sites that access would be denied to the very vehicles which need access to make the facility economically viable - and which have driven over the same piping for a dozen or more years. ... Location and marking of such piping so that it could be temporarily protected, or avoided, would appear to be an acceptable alternate. While it could be argued that providing such protection or rerouting emergency equipment is not practical, it is at least as practical as expecting such equipment to comply with weight restriction signs!” (76)

PE discretion. “This provision recommends the posting of vehicle weight restrictions. However, it would be preferable for EPA to require that a PE be involved in evaluating this question and that the PE’s conclusions be documented and implemented.” (43)

Requirement, not recommendation. The rule “should require, rather than recommend, that vehicular weight restrictions be posted to prevent damage to underground piping.” (44, 52)

Rerouting. “Location and marking of such piping so that it could be temporarily protected, or avoided, would appear to be an acceptable alternate. While it could be argued that providing such protection or rerouting emergency equipment is not practical, it is at least as practical as expecting such equipment to comply with weight restriction signs!” (76)

Applicability.

Airports. The proposal is “unreasonable at airport facilities where some buried piping/hydrant systems run under ramp surfaces. Posting of signs in such open areas would be impractical and impact operations.” (107)

Large facilities. Recommendation should apply only “to large facilities because only large facilities will have the type of tanker trucks which would potentially damage underground piping.” (34, 75, 182)

Railroads. “This recommendation is overly broad. Railroads have a large amount of piping under track that is built to withstand maximum loads from vehicular traffic. It is unnecessary to require signs for such pipes. Furthermore, it would be costly to post signs wherever there is underground piping on railroad property.” (57)

Vaulted tanks. “Because VAST technology requires all openings and fittings to be placed at the top of the tank, and requires the dike in the form of a concrete vault to immediately encompass the secondary containment, the risk of damage from vehicular traffic has been significantly reduced, making the provisions in §112.8(d)(5) unduly burdensome and costly to sites using VAST technology.” (65)

Costs. We failed to recognize the substantial costs to owners or operators of determining accurate weight restrictions. (76)

Guidance. “...(U)nless further guidance is provided on the method of determining an acceptable weight limit, this item should be eliminated.” (169)

Response: *Support for proposal.* We appreciate commenter support.

Applicability. The requirement to warn vehicular traffic so that no vehicle will endanger aboveground piping or other oil transfer operations applies to all facilities, large or small, because vehicular traffic may endanger aboveground piping or other transfer operations at all facilities. Warnings may include verbal warnings, signs, or marking and temporary protection of piping or equipment. No particular height restriction is incorporated into the rule. Rather, aboveground piping at any height must be protected from vehicular traffic unless the piping is so high that all vehicular traffic passes underneath the piping. In this case, or where the requirement is infeasible, you may be able to use the deviation provision in §112.7(a)(2) if you explain your reasons for nonconformance and provide equivalent environmental protection. We have deleted the clause concerning the size of vehicles that may endanger piping or oil transfer operations because the owner or operator may not be able to determine precisely when the size or weight of a vehicle which would cause such endangerment.

In response to commenters who suggested that the posting of signs is impractical and might impact operations, or would be very costly, we note that you may deviate from the requirement under §112.7(a)(2) if you explain your reasons for nonconformance and provide equivalent environmental protection.

Costs. Even though we did not include the recommendation in the final rule, we included the estimated costs of the proposal in our 1991 economic analysis.

New regulatory structure. We see no need for a new regulatory structure because buried piping is likely to be an appurtenance to a completely buried tank and as such, is likely to

be regulated under 40 CFR part 280. If the piping is not of a completely buried tank, the appurtenance is likely covered by part 112 requirements. Therefore, a new regulatory structure is unnecessary.

Weight restriction posting. We deleted the proposed recommendation concerning weight restrictions as it relates to underground piping from rule text, but still support it when appropriate. We include only mandatory items in this rule because we do not wish to confuse the regulated public as to what is mandatory and what is discretionary. We decline to make the recommendation a requirement because we believe the appropriate posting of weight restrictions should be a matter of good engineering practice.

Category XII: Onshore production facility Plan requirements

XII - A: Production facilities (general requirements) - §112.9(a)

Background: In 1991, we proposed to reorganize §112.7(e) of the current rule into four sections (§§112.8, 112.9, 112.10, and 112.11), based on facility type. We proposed §112.7(e)(5) of the current rule as §112.9 in 1991.

Comments: *Cost.* Section §112.9 of the proposed rule would result in an increased economic burden on owners or operators of production facilities – particularly small facilities with “stripper” wells. “For these wells, any substantial capital expense or increase in operating costs will very likely result in premature closure.” (42, 67, 91, 101)

Performance standards. “Arbitrary standards for onshore and offshore production facilities (40 CFR §§ 112.9 and 112.11) should be deleted and replaced by reasonable performance standards.” (86)

Reorganization of rule. “The requirements for oil production facilities should be consolidated with similar requirements for on-shore facilities. The few differences between the two types of facilities could be handled on a call-out basis. As §§ 112.8 and 112.9 are now written, they are similar but not identical. There appears to be no justification for the difference.” (111)

Response: *Cost.* EPA considered cost factors in finalizing the requirements in this rule. We believe that facilities in compliance with the current rule will incur minimal additional cost due to the revisions in this rule. Many of the provisions we proposed in 1991 that commenters believed were too costly were not finalized in the rule. In addition, in today’s rule, we have provided flexibility in several ways. Furthermore, we are finalizing other provisions in this rule which will reduce burden in other ways and will exempt certain facilities from having to prepare a Plan. EPA has also prepared an assessment of the costs of rule compliance, which is discussed in part VI.F (Regulatory Flexibility Act) of today’s preamble, and we have included the specific comments related to costs and our responses in relevant sections of this preamble.

We agree that we should require performance standards in this regulation rather than prescriptive standards. Throughout the rule we generally allow for the application of industry standards where the standards are both specific and objective, and their application may reduce the risk of discharges to and impacts to the environment. We also permit the owner or operator greater flexibility by allowing the use of deviations under either §112.7(a)(2) or (d).

Performance standards. The final rule generally provides for use of performance standards rather than design standards. See §§112.7(a)(2) and (d).

Reorganization of rule. We generally agree that the current rule is adequate and effective in preventing discharges. We have reorganized the rule into subparts and sections based

on the type of oil stored or used and the type of facility for clarity and ease of use. The reorganization is not a substantive change.

XII - B: Facility drainage - §112.9(b) (proposed as §112.9(c))

XII - B(1) Diked storage area drainage - §112.9(b)(1)

Comments: *Applicability.* Urges a small facility exemption from this requirement because the recordkeeping involved was too burdensome.

Editorial changes and clarifications. “The language in §112.9(c)(1) stating ‘...where an accidental discharge of oil would have a reasonable possibility of reaching navigable waters....’ does not agree with the wording in §112.1(b)(1) stating ‘...which due to their location could reasonably be expected to discharge oil in quantities that may be harmful....’ These sections should be made consistent.” (154) “The requirement to have all drains closed on dikes around storage tanks might preclude engineering measures (stand pipes) designed to handle flow-through conditions at water flood oil production operations, where large volumes of water may be directed to oil storage tanks if water discharge lines on oil-water separators become plugged.” (28, 31, 101, 165)

Recordkeeping. The recordkeeping provisions in proposed §112.9(c)(1) are overly burdensome and of little benefit. (28, 58)

Small facilities. We should exclude small facilities from the recordkeeping requirements. (58)

Response: *Applicability.* We believe that this requirement must be applicable to both large and small facilities to help prevent discharges as described in §112.1(b). The risk of such a discharge and the accompanying environmental damage may be harmful whether it comes from a large or small facility. We disagree that the recordkeeping is burdensome. If you are an NPDES permittee, you may use the stormwater drainage records required pursuant to 40 CFR 122.41(j)(2) and 122.41(m)(3) for SPCC purposes, thereby reducing the recordkeeping burden.

Editorial changes and clarifications. In response to the commenter’s suggestion, the reference to “navigable waters” becomes a reference to “a discharge as described in §112.1(b).” “Central treating stations” becomes “separation and treating areas.” Such areas might be centrally located or located elsewhere at the facility and might include both separation and treatment devices and equipment. The reference to “rainwater is being drained” becomes “draining uncontaminated rainwater.” We clarify that accumulated oil on rainwater must be disposed of in accord with “legally approved methods,” not “approved methods.”

Alternatives. We should modify proposed §112.9(c)(1), allowing owners or operators to recycle accumulated oil on the rainwater by *other methods*. This modification would allow flexibility to seek alternate, environmentally sound recycling methods. (L12)

Engineering methods. “Equivalent” measures referenced in the rule might, depending on good engineering practice, include using structures such as stand pipes designed to handle flow-through conditions at water flood oil production operations, where large volumes of water may be directed to oil storage tanks if water discharge lines on oil-water separators become plugged. Any alternate measures must provide environmental protection equivalent to the rule requirement.

Industry standards. Industry standards that may assist an owner or operator with facility drainage include API Recommended Practice 51, “Onshore and Oil and Gas Production Practices for Protection of the Environment.”

Recordkeeping. We agree that a five-year record retention period is longer than necessary and have deleted the proposed requirement in favor of the general requirement in §112.7(e) to maintain records for three years. However, this requirement must apply to both large and small facilities to help prevent discharges as described in §112.1(b). The risk of such a discharge and the accompanying environmental damage from a small facility may be as harmful as from a large facility. If you keep stormwater drainage records required pursuant to 40 CFR 122.41(j)(2) and 122.41(m)(3), you may use such records for SPCC purposes, thereby reducing the recordkeeping burden.

XII - B(2): Drainage ditches, accumulations of oil - §112.9(b)(2) (proposed as §112.9(c)(2))

Background: Under §112.7(e)(5)(ii)(B) of the current rule, an owner or operator of an onshore production facility must inspect and remove accumulations of oil from field drainage ditches, oil traps, sumps, or skimmers. In 1991, we proposed to redesignate §112.7(e)(5)(ii)(B) as §112.9(c)(2), and to require the owner or operator to remove oil-contaminated soils as well as accumulated oil within 72 hours, if immediate removal was not feasible. We solicited comments on the appropriate amount of time for discovery and removal of accumulated oil, recognizing that production facilities may not be staffed during a given 72-hour period.

Comments: *Authority.* EPA lacks CWA authority for this provision. CWA addresses clean water, not “clean dirt.” (28, 58)

Clarifications - “accumulation,” “oil-contaminated soil.” We should clarify the terms *accumulation* and *oil-contaminated soil* in the context of the proposed requirement to remove accumulated oil or oil-contaminated materials within 72 hours. (28, 58, 71, 101, 153)

Inspection schedule. “Field drainage ditches, etc., should have a schedule set for inspection of accumulations of oil. OHIO EPA recommends monthly inspections, and within 24-hours of a 25-year storm event.” (27)

72-hour cleanup standard.

Opposition to proposal.

Bioremediation. “Accumulated oil should be picked up and properly hauled. However, problems associated with oil-contaminated soil can often be addressed as well or better if the material is left in place. Bioremediation techniques and other measures which may be used under existing laws are less expensive and create less waste than removal procedures.” Proposal may limit bioremediation or other cleanup techniques. Clean up should be allowed in accordance with State and local requirements. (31, 67, 86, 90, 91, 99, 101, 144, 145, 160, 167, 173)

Costly. “Landfill space is at a premium and on-site bioremediation has the potential to prevent environmental harm in a more cost effective manner with equivalent environmental results.” (99, 101, 160)

Impractical or impossible. “In addition, the 72-hour requirement is unreasonable in many instances. In cases where a significant amount of oil has been released, or in remote locations, where it may be difficult to mobilize the equipment needed, or in snowy areas where leaks cannot be easily observed, it may be virtually impossible to complete cleanup within 72 hours.” (31, 67, 71, 86, 91, 101, 153, 160, 167, 173, 175, 187, L12, L18) An owner or operator may be unable to obtain proper regulatory authorization to remove and dispose of oil-contaminated soil within 72 hours. (31, 86, 153) Removal within 72 hours from the time of the spill would be difficult at an unattended facility. (102) Frequently, it is technically infeasible to remove contaminated soil because of “structural concerns” or the volume of soil. (153, 173) Some facilities have oil-contaminated soil from past spills. (162)

Landfill disposal problems. The requirement to remove all oil-contaminated soil could compound landfill disposal capacity problems. (99, 165, L15)

Navigable waters. We should require the owner or operator to remove the accumulation of oil only if that oil might reach navigable waters. (L12)

Safety or health problems. The 72-hour requirement could pose a safety or health hazard to employees. (102)

Unnecessary. The 72-hour requirement would be excessive and unnecessary because spill response procedures already must be described in the SPCC Plan. (31, 86) It is unnecessary to remove all spilled oil within 72 hours if the containment system is designed to be impervious to oil for a longer period of time. (71)

Time calculations.

Discovery. Since the time when the spill occurred may be unknown, any time frame for removing oil or oil-contaminated materials should be based on when the spill is discovered. (67, 71, 91, 102, 133, 153, 167, 173)

72-hour cleanup standard - suggested alternatives.

As soon as practical. We should require that the owner or operator complete clean-up operations “as soon as practical” or “within a timely manner,” or “after the spill is discovered.” (78, 101, 102, 133, 153, 167, 173, 187)

Immediately upon discovery. We should revise the proposal to require that clean-up operations begin immediately upon discovery of a spill, and that every reasonable effort be made to complete the clean-up within 72 hours. (153)

Initiation within 72 hours. We should require the initiation of remedial activities to begin within 72 hours from when the spill occurred. (18)

Precautions. “During remediation operations, precautions are taken to prevent contamination of surface water by stormwater runoff. A dike or ditch may be constructed around the area, or oil absorbent materials may be placed around the area. Covering with plastic film is another acceptable means to temporarily prevent stormwater contamination during remediation operations.” (99)

Response: Authority. We have adequate authority to require cleanup of an accumulation of oil, including on soil and other materials, because section 311(j)(1)(C) of the CWA provides EPA with the authority to establish procedures, methods, and equipment and other requirements for equipment to prevent discharges of oil. The broad definition of “oil” under CWA section 311(a)(1) covers “oil refuse” and “oil mixed with wastes other than dredged spoil.” If field drainage systems allow the accumulation of oil on the soil or other materials at the onshore facility and that oil threatens navigable water or adjoining shorelines, then EPA has authority to establish a method or procedure, i.e., the removal of oil contaminated soil, to prevent that oil from becoming a discharge as described in §112.1(b). The cleanup standard under this paragraph requires the complete removal of the contaminated oil, soil, or other materials, either by removal, or by bioremediation, or in any other effective, environmentally sound manner.

Clarifications - “accumulation,” “oil-contaminated soil.”

Accumulation. We retain the term “accumulation of oil,” but elaborate on its meaning. “Accumulation of oil” means a discharge that causes a “film or sheen” within the field drainage system, or causes a sludge or emulsion there (see 40 CFR 110.3(b)). An accumulation of oil includes anything on which the oil gathers or amasses within the field drainage system. An accumulation of oil may include oil-contaminated soil or any other oil-contaminated material within the field drainage

system. See *also* the discussion of “accumulation of oil” included with the response to comments of §112.8(c)(10).

Oil-contaminated soil. We eliminated the term “oil-contaminated soil” because oil must accumulate on something, such as materials or soil.

Inspection schedule. We have retained the “regularly scheduled intervals” standard for inspections. This standard means regular inspections according to industry standards or on a schedule sufficient to prevent a discharge as described in §112.1(b). Whatever schedule for inspections is selected must be documented in the Plan. We decline to specify a specific interval because such an interval might become obsolete with changing technology.

72-hour cleanup standard. We agree that the 72-hour cleanup standard might preclude bioremediation and have therefore deleted it. Instead we establish a standard of “prompt cleanup.” “Prompt” cleanup means beginning the cleanup immediately after discovery of the discharge or immediately after any actions necessary to prevent fire or explosion or other imminent threats to worker health and safety.

Precautions. We note that an owner or operator may choose to spread plastic film over the diked area to prevent the occurrence of an accumulation of oil. However, he must dispose of the film properly.

XII - C: FEMA requirements - proposed §112.9(c)(3)

Comments for this section are addressed in Subcategory XVI-B: State programs, SARA Title III, wellhead protection, flood-related requirements, OSHA, and industry standards.

XII - D: Production facilities - bulk storage containers - §112.9(c) (proposed §112.9(d))

XII - D(1) Material and construction - §112.9(c)(1)

Background: Section 112.7(e)(5)(iii)(A) of the current rule provides that for an onshore production facility, tanks should not be used for storing oil unless the tank material and construction are compatible with the material stored and the storage conditions. In 1991, we proposed to redesignate the current rule provision as §112.9(d)(1), and to recommend that tank construction and operation conform to relevant industry standards because applying these standards reflects good engineering practice.

Comments: *Local standards.* “OOGA seeks clarification that USEPA recognizes that local standards sometimes control industry standards on certain issues and that such could occur under this provision.” (58)

Recommendation v. requirement. ‘Proposed section 112.9(d) should require, rather than recommend, that tanks meet industry standards. At a date certain, all existing tanks

should be upgraded to meet industry standards. Moreover, all new and reconstructed tanks should be subject to applicable codes.” (44)

Response: *Recommendation v. requirement.* We are retaining the mandatory requirement to use no container for the storage of oil unless its material and construction are compatible with the material stored and the conditions of storage, as proposed. We have deleted the recommendation that materials, installation, and use of new tanks conform with relevant portions of industry standards because we do not wish to confuse the regulated public over what is mandatory and what is discretionary. However, we endorse its substance. In most cases good engineering practice and liability concerns will prompt the use of industry standards. See §112.3(d)(1)(iii). In addition, a requirement is not necessary or desirable because local governmental standards on construction, materials, and installation sometimes control industry standards on these matters.

XII - D(2) Secondary containment - §112.9(c)(2)

Background: In 1991, we proposed in §112.9(d)(2) (redesignated as §112.9(c)(2) in the final rule) (§112.7(e)(5)(iii)(B) of the current rule) to clarify that required secondary containment must include sufficient freeboard for precipitation. We also repropose the requirement to confine drainage from undiked areas.

Comments: *Applicability.*

Oil leases. The proposal is “is too vague and comprehensive to be applied to oil leases. It would be applicable to entire leases covering hundreds of acres if interpreted improperly.” (31, 101, 165, L15)

Clarification.

Accumulation. “Is accumulated oil and contaminated soil to be removed from diked areas under this provision? What is contaminated soil? What are the cleanup standards under this provision? What is an ‘accumulation’.” (58)

Methods. We should not allow alternate secondary containment systems such as those outlined in §112.7(c)(1) of this part. (121)

NPDES rules. “The new EPA NPDES storm water program clearly and very thoroughly regulates potential precipitation-drainage related pollution from these sources. The requirements in this sentence amount to a duplicative regulatory requirement by the same agency.” (28, 101, L12)

Sufficient freeboard. We do not set a standard for “sufficient” freeboard. The owner, operator, or Professional Engineer (PE) should be able to determine the appropriate size for secondary containment on a site-by-site basis. (75)

Response: Applicability. The requirement applies to oil leases of any size. Secondary containment is not required for the entire leased area, merely for the contents of the largest single container in the tank battery, separation, and treating facility installation, with sufficient freeboard to contain precipitation.

Clarification.

Accumulation. We retain the term “accumulation of oil,” but elaborate on its meaning. “Accumulation of oil” means a discharge that causes a “film or sheen” within the field drainage system, or causes a sludge or emulsion there (see 40 CFR 110.3(b)). An accumulation of oil includes anything on which the oil gathers or amasses within the field drainage system. An accumulation of oil may include oil-contaminated soil or any other oil-contaminated material within the field drainage system. See *also* the discussion of “accumulation of oil” included with the response to comments of §112.8(c)(10).

Methods. We disagree that we should not allow alternate secondary containment systems such as those in §112.7(c)(1). We note that no single design or operational standard is appropriate for all onshore production facilities. An owner or operator must choose the appropriate secondary containment system compatible with good engineering practice.

NPDES rules. We deleted the proposed reference to undiked areas “showing a potential for contamination” because drainage from any undiked area poses a threat of contamination. When drainage from such areas is covered by storm water discharge permits, that part of the BMP might be usable for SPCC purposes. There is no redundancy in recordkeeping requirements, because you can use your NPDES records for SPCC purposes.

Sufficient freeboard. In response to the comment as to how an owner or operator might determine how much freeboard is sufficient, we have revised the rule to provide that freeboard sufficient to contain precipitation is the standard. We have recommended a standard for sufficient freeboard in the final rule. That standard is sufficient freeboard to contain a 25-year, 24-hour storm event. However, because of the difficulty and cost of securing recent information concerning such events, we are not making this a rule standard.

XII - D(3): Container inspection - §112.9(c)(3)

Background: Section 112.7(e)(5)(iii)(C) of the current rule provides that production tanks must be visually inspected on a periodic schedule and the foundation and supports of aboveground tanks must be inspected for deterioration. In 1991, we proposed to designate §112.7(e)(5)(iii)(C) as §112.9(d)(3) (redesignated as §112.9(c)(3) in the final rule) and to require tank examinations at least once a year. We also proposed that an owner or operator keep schedules and records of examinations for the last five years, regardless of change in ownership.

Comments: *Extent of inspection.*

Visual inspections. “It is not practicable to internally visually examine tanks on an annual basis due to the number that would need to be taken out of service at any one time to meet the requirement. API agrees with scheduled visual external examinations of tanks but believes that internal examinations and inspections should be accomplished in accordance with API Recommended Practice 12R1.” (67, 85, 167)

Frequency of inspection.

Support for proposal. “Ohio EPA agrees with the provision for annual inspections of tank batteries, and with the requirement to keep the record of inspection for five years.” (27)

More frequent inspections. We should direct owners or operators to examine production tanks quarterly. (121)

Opposition to proposal. “Requiring an annual tank inspection and record maintenance is an unnecessary expense.” (101)

“If possible.” We should require examining a tank’s aboveground foundation and supports only “if practical” or “if possible.” An owner or operator might be unable to inspect a tank where the foundation settled or there is a lack of space. (67, 173)

Triennial inspection. Documenting an annual inspection would increase paperwork with no benefit to small facilities. The existing provision is adequate. “More importantly, the three year review of the SPCC Plan pursuant to section 112.5(b) is more than sufficient to document a visual inspection of the facilities.” (58, 70)

Record maintenance.

Opposition to proposal. “OOGA is uncertain of the recordkeeping requirement under this provision. Undeniably, owners of crude oil production facilities routinely inspect their storage tanks. To document these inspections seems to serve no useful purpose.” (58, 70) “The agency does not indicate a reason for increasing the records-retention requirement from three to five years. Most if not all CWA related programs have a mandatory three-year records retention requirement. EPA needs to explain their reason(s) for the more costly five-year mandatory requirement. This request is made for every EPA mandatory five-year record retention requirement in this proposed rule.” (L12)

PE Certification. “Regular inspections and record maintenance provisions should not require the certification of a Registered Professional Engineer, which is one

possible interpretation of these requirements, as records are included in the Plan.” (101, 165, L15)

Phase-in. The rule should provide for a two-year phase-in period so that the facility will have the required five years of records. (102)

Response: *Extent of inspection.* We disagree that the inspection of containers should be limited to external inspection. Internal inspection is also necessary to detect possible flaws that could cause a discharge. The inspection must also include foundations and supports that are on or above the surface of the ground. If for some reason it is not practicable to inspect the foundations and supports, you may deviate from the requirement under §112.7(a)(2), if you explain your rationale for nonconformance and provide equivalent environmental protection.

API standards. Regarding the comment that we should require internal examinations and inspections in accordance with an API practice, we note that while API standards may be sufficient for many facilities, no single design or operational standard is appropriate for all non-transportation-related facilities. An owner or operator should choose the appropriate standard in the exercise of good engineering practice.

Visual inspection. Visual examinations must be in accordance with §112.9(c)(3) specifications, and must include the foundations and support of each container.

Frequency of inspection. We have maintained the current standard for frequency of inspection because we agree that inspections in accordance with industry standards are necessary. Those standards may change with changing technology, therefore, a frequency of “periodically and upon a regular schedule” preserves maximum flexibility and upholds statutory intent.

Owner/operator discretion. We decline to give an owner or operator absolute discretion to inspect if practical or possible; instead we recommend inspection according to industry standards. Whatever frequency of inspection that is chosen must be noted in the Plan.

Record maintenance. Recordkeeping is necessary to document compliance with the rule. We have deleted the proposed requirement to maintain records of these inspections for five years, irrespective of ownership, because it is redundant with the general requirement in §112.7(e) to maintain Plan records. Section 112.7(e) requires record maintenance for three years. However, you should note that certain industry standards (for example, API Standard 653 or API Recommended Practice 12R1) may specify that an owner or operator maintain records for longer than three years.

PE Certification. We do not require a PE to certify inspection records because such records are not part of the Plan.

XX - D(4) Good engineering practice - tank batteries - §112.9(c)(4)

Comments: *Good engineering practice.* “Proposed section 112.9(d)(4) should contain a requirement for fail-safe engineering of oil production facility tanks, just as onshore bulk storage is required to be fail-safe engineered (see proposed section 112.8(c)(8)), to avoid confusion among the regulated community and to improve spill prevention.” (27, 44)

Small facilities. “Single tanks with a capacity of 10,000 gallons or less and facilities with a capacity of 40,000 gallons or less should be exempt from this section.” (28, 101)

Too expensive. “Engineering tanks into a ‘fail-safe engineering condition’ is prohibitively expensive and unnecessary as far as Appalachian production is concerned.” (101)

Vacuum protection. “Installation of vacuum protection on every tank could cost in excess of \$100/tank. We doubt this has been calculated in the potential fiscal impact of these proposals.” (28, 31, 101, 165)

Response: *Good engineering practice.* We agree with the commenter that we should retain this section as a requirement both to improve spill prevention and to avoid confusion among the regulated community because of the similar requirement for bulk storage containers at facilities other than production facilities. Therefore, there are no new costs. Nevertheless, we believe that the costs of these measures are not excessive for small or large facilities because you have flexibility as to which measures you use, and may choose the least expensive alternative listed in §112.9(c)(4). For example, should vacuum protection be too costly, you are free to use another alternative. Furthermore, you may also deviate from the requirement under §112.7(a)(2) if you can explain nonconformance and provide equivalent environmental protection by some other means. We revised the paragraph on vacuum protection to clarify that the rule addresses any type of transfer from the tank, not merely a pipeline run.

Vacuum protection. We note that the rule does not require vacuum protection, merely consideration of its use. You may choose to use vacuum protection, another of the listed measures, or an alternative that provides equivalent environmental protection.

XII - E: Facility transfer operations - §112.9(d) (proposed as §112.9(e))

Background: Current §112.7(e)(5)(iv) provides requirements for facility transfer operations for onshore oil production facilities. In §112.7(e)(5)(iv)(A), an owner or operator is required to examine “periodically on a scheduled basis” all aboveground valves and pipelines. In §112.7(e)(5)(iv)(B), an owner or operator is required to examine salt water disposal facilities “often.” In §112.7(e)(5)(iv)(C), an owner or operator is required to have a program of flowlines maintenance for their production facilities and we list specific elements that the program must include, such as periodic examinations and adequate records, as appropriate for the individual facility.

In 1991, we redesignated §112.7(e)(5)(iv)(A)-(C) as §112.9(e)(1)-(3), and proposed several changes. In §112.9(e)(1), we proposed requiring an owner or operator to examine aboveground valves and piping monthly, and to include examination schedules and records in the Plan for five years. We did not propose any changes to §112.9(e)(2). In §112.9(e)(3), we maintained the requirement that an owner or operator have a flowlines maintenance program, but proposed recommending, rather than requiring, that he include in the flowlines maintenance program the specific elements that the current rule requires. We proposed to change this requirement to a recommendation because the circumstances of locations, staffing, and design vary between facilities. We also proposed changing the periodic examination requirement to a recommendation that an owner or operator examine flowlines monthly.

XII - E(1) - Inspection of aboveground valves and piping - §112.9(d)(1)

Comments: *Editorial suggestion.* The rule should be clarified that “only inspections related to transfer operations are intended by inserting ‘associated with transfer operations’ between ‘piping’ and ‘shall’ in the first line of proposed 112.9(e)(1).” (75)

Frequency of inspection.

Opposition to proposal.

Burdensome. Such a requirement would be unreasonably burdensome. The condition of valves and piping does not change significantly within a month. (67, 91, 133, 173, 187, L18)

Unwarranted. “(I)nformal, regular visual inspections, with no record keeping requirements” should continue. (67) Field personnel routinely notice and fix any oil leaks associated with aboveground valves and pipelines. (101) Monthly inspections of aboveground valves and pipelines “may not be warranted.” (175)

Suggested alternatives.

Every 6 months. “The condition of valves and piping does not change significantly within a month’s time. Therefore, a more appropriate formal inspection frequency with documentation requirements is semi-annual. More informal, regular visual inspections, with no record keeping requirements should continue.” (67, 91, 133, 173, 187, L18)

Performance standard instead. “The inspections standard ... should be amended to reflect a performance standard instead of a prescribed monthly inspection.... A generalized performance standard should be included that requires a minimum inspection interval, such as annual inspection, which could be altered to meet specific facility conditions.” (31, 86, 160)

Recordkeeping.

Opposition to proposal. The proposed record keeping requirement is unnecessary, of little value, and “prohibitively expensive.” (28, 101) Well attendants check Appalachian Basin well sites (including all aboveground piping, valves, joints, gauges, pipe supports, etc.) on a near-daily basis, noting necessary repairs. Documenting monthly examinations is unnecessary and a “waste of limited resources and time.” It is meaningless to keep records of inspections where no problems were found. (71)

All facilities. We should delete the record keeping requirement for all facilities; documenting monthly visual inspections would drastically increase paperwork with no benefit for small facilities. (70)

PE certification. We should not require PE approval of the owner’s or operator’s maintenance records, as these records are included in the Plan. (101, 165, L15)

Small facilities. We should exempt small facility owners or operators from the requirement to include aboveground valve and pipeline examination schedules and records in the Plan for five years. (58, 86)

Response: *Editorial suggestion.* We agree with the commenter and have changed the rule language to provide that §112.9(d)(1) applies to “aboveground valves and piping associated with transfer operations.”

Frequency of inspections. We have retained the current inspection frequency of periodic inspections, but editorially changed it to “upon a regular schedule.” Our decision accords with the comment which sought a performance standard instead of a prescribed monthly inspection. The standard of inspections “upon a regular schedule” means in accordance with industry standards or at a frequency sufficient to prevent discharges as described in §112.1(b). Whatever frequency of inspections is selected must be documented in the Plan.

Recordkeeping. We agree that a five-year record retention period is longer than necessary and have deleted the proposed requirement in favor of the general requirement in §112.7(e) to maintain records for three years. However, comparison records for compliance with certain industry standards may require an owner or operator to maintain records for longer than three years.

PE certification. PE certification of these inspections and records is not required.

Small facilities. We disagree that we should exempt either a large or small facility owner or operator from the requirement to include aboveground valve and pipeline examination schedules and records in the Plan because those records are needed to document compliance with the rule.

XII - E(2) Salt water disposal facilities - §112.9(d)(2)

Comments: *Sudden change in temperature.* “A sudden change of temperature” is a rather vague indicator of potential system upsets. This commenter assumes that the Agency means a rather sudden ‘drop’ (as in freezing temperatures) that could cause system upsets. This requirement needs further clarification.” (187)

Applicability. Salt water disposal facility examination requirement should not apply to storage facilities with *de minimis* amounts of oil. (28, 58, 101)

Frequency of inspection. To be consistent with other proposed inspection frequencies, the inspection frequency of salt water disposal facilities should be quarterly, rather than weekly. (114)

Response: *Applicability.* The rule applies to any regulated facility with salt water disposal if the potential exists to discharge oil in amounts that may be harmful, as defined in 40 CFR 110.3. This standard is necessary to protect the environment.

Frequency of inspections. Inspections of these facilities must be conducted “often.” “Often” means in accordance with industry standards, or more frequently, if as noted, conditions warrant. Whatever frequency of inspections chosen must be documented in the Plan.

Sudden change in temperature. A sudden change in temperature means any abrupt change in temperature, either up or down, which could cause system upsets.

XII-E(3) Flowlines maintenance - §112.9(d)(3)

Background: In 1991, in §112.7(e)(3) (redesignated in the final rules as §112.9(d)(3)), we maintained the requirement that an owner or operator have a flowlines maintenance program, but proposed recommending, rather than requiring the owner or operator to include in the flowlines maintenance program the specific elements that the current rule requires. We also changed the periodic examination requirement to a recommendation that owners or operators examine flowlines monthly.

Comments: *Applicability.*

Small facilities. Asks that we exempt small facilities from the flowlines maintenance program requirement. (58)

Frequency of inspections.

Opposition to proposal. We should delete the entire recommendation, and keep only the requirement that production facility owners or operators have a flowlines maintenance program. (121)

Costly. It is cost-prohibitive and impossible for owners or operators of Appalachian oil gathering line systems to provide corrosion protection for the bare steel pipe used in these systems. The “use of coated lines and cathodic protection is cost prohibitive.” (28, 31, 101, 165, L15)

Impossible. “These oil gathering line systems are buried in colder parts of the Appalachian basin, and monthly inspection of them is thus not possible.” (28, 31, 165, L15)

Lack of manpower. Owners or operators do not have enough manpower to inspect flowlines monthly. (91, 133, 173)

Unwarranted. “Unless a flowline is known to have problems, monthly inspections may not be warranted. Many production facilities are unmanned and the cumulative length of flowlines can be several miles, so the proposed monthly timeframe may be burdensome.” (175)

Suggested inspection alternatives.

Periodic. “Periodic inspections based on engineering judgment and historical data are sufficient to detect any significant deterioration in flowline condition.” (67, 85, 91, 160, 173, 175)

Quarterly. (114)

Semi-annual. (L18)

Annual. (133).

Response: *Applicability.* A program of flowlines maintenance is necessary to prevent discharges both at large and small facilities. However, we have deleted the proposed recommendation regarding the specifics of the program from the rule. We took this action because we are not including recommendations in the rule in order not to confuse the public over what is mandatory and what is discretionary. This rule contains only mandatory requirements.

Corrosion protection, flowlines replacement. While we have deleted the recommendation from rule text due to reasons explained above and therefore, the rule imposes no new costs, we recommend corrosion protection, we recommend corrosion protection, and flowlines replacement when necessary, because those measures help to prevent discharges as described in §112.1(b).

Cost. We disagree that the cost of this requirement is excessive or impossible. We do not prescribe the specifics of the program and the owner or operator may use any program (not necessarily the most expensive) effective to maintain the flowlines and prevent a discharge as described in §112.1(b). The requirement is a current one and is necessary to prevent discharges as described in §112.1(b).

Frequency of inspections. In the proposed recommendation we suggested that you conduct monthly inspections for a flowlines maintenance program. We now recommend that you conduct inspections either according to industry standards or at a frequency sufficient to prevent a discharge as described in §112.1(b). Under §112.3(d)(1)(iii), the Professional Engineer must certify that the Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards.

Category XIII: Plan requirements for onshore drilling/workover facilities - §112.10

Background: Under §112.7(e)(6)(i) of the current rule, an onshore drilling and workover facility owner or operator must position or locate mobile drilling or workover equipment to prevent spilled oil from reaching navigable waters. Section 112.7(e)(6)(ii) requires that, depending on location, it may be necessary to use catchment basins or diversion structures to intercept and contain spills of fuel, crude oil, or oily drilling fluids. Section 112.7(e)(6)(iii) requires the owner or operator install a blowout prevention (BOP) assembly and well control system before drilling below any casing string or during workover operations.

In 1991, we redesignated §112.7(e)(6)(i), (ii), and (iii) as §112.10(b), (c), and (d), respectively. We proposed to add §112.10(a), which proposed that in addition to the specific spill prevention and containment procedures listed under §112.10, an onshore oil drilling and workover facility owner or operator must also address the general requirements listed in §112.7. Under proposed §112.10(b), an owner or operator would have to locate mobile drilling or workover equipment to prevent spilled oil discharges. Under proposed §112.10(c), we proposed that depending on the location, catchment basins or diversion structures may be necessary to intercept and contain spills of fuel, crude oil, or oily drilling fluids. Under proposed §112.10(d), we proposed to require that when necessary, before drilling below any casing string or during workover operations, an owner or operator install a blowout prevention assembly and well control system capable of controlling any wellhead pressure that may be encountered while that blowout assembly is on the well.

Comments: *Support for proposal.* Section §112.10 requirements should include workover and drilling equipment, human activity is often associated with accidental releases. (27)

§112.10(a). “Change to: ‘In addition to the specific spill prevention and containment procedures listed under this section, onshore oil drilling and workover facilities must also address the requirements listed under section 112.7 and paragraph 112.8(c)(11) in the SPP.’ (Note: the caveat ‘excluding production facilities’ should probably be removed from 112.8(c).)” (121) In §112.10(a), we should require an onshore oil drilling and workover facility owner or operator to “address the applicable general requirements.” (128)

Editorial suggestion. Asks for a definition of “onshore drilling and workover facilities.” (154)

§112.10(b) - We should require positioning or locating mobile drilling or workover *facilities* to prevent *oil discharges*. (121) “We are categorically opposed to this requirement. The mobile drilling and workover contractor has absolutely no control as to the location of the rig unit.... The contractor has no input as to the site design nor responsibility for its maintenance.” (128) Section 112.10(b) is unnecessary because it duplicates Bureau of Land Management (BLM) and State regulatory programs. (167) We should change

§112.10(b) to clarify that an owner or operator must prevent spilled oil discharges to *navigable water*. (L12)

§112.10(d) - The rule should be revised to provide that: “Well service jobs, such as installing a rod pumping unit, may not require a BOP assembly and associated well control system.” “BOP are not now, and should not become, a requirement for all operations. Service jobs such as the change out of a rod pumping unit, or the batch treatment of a well with corrosion inhibitor are minimal risk operations and do not normally require the use of BOP systems. These service jobs are minimal risk because they can be performed with existing wellhead equipment in place. If any unexpected pressure is incurred during the service job, then existing valves can be utilized to control the pressure.” (67, 91)

Gauge negative. We should explain the term *gauge negative*. (110)

Response: *Support for proposal.* We appreciate the commenter support.

§112.10 - We disagree that an onshore oil drilling and workover facility owner or operator must address the §112.8(c)(11) requirements for mobile or portable oil storage tanks unless he has such containers. Section 112.8(c)(11) pertains only to onshore bulk storage containers (except production facilities).

§112.10(a) - We also disagree that it is necessary to revise the rule to require compliance with *applicable* §112.7 general requirements because the owner or operator must address all general requirements in §112.7 and all specific requirements in subparts B or C, as appropriate, for the type of facility he owns or operates. If a requirement is not applicable, the owner or operator must explain in the Plan why.

Editorial suggestion. The new definition for “production facility” in §112.2 includes the procedures, methods, and equipment referenced in this section, making a definition of “onshore drilling and workover facilities” unnecessary.

§112.10(b) - We agree with the commenter that the contractor is not normally responsible for site location, nor site design or maintenance. Such decisions are the responsibility of the facility owner or operator. The owner or operator of the facility has the responsibility to locate mobile equipment so as to prevent a discharge as described in §112.1(b).

We disagree that we should change the word *equipment* to *facilities* in §112.10(b). A facility may include structures, piping, and equipment. This paragraph is directed to the threat of discharge from equipment.

We have revised §112.10(b) to provide that an owner or operator must position or locate mobile drilling or workover equipment to prevent *a discharge as described in §112.1(b)*, rather than to prevent *spilled oil discharges*, as proposed. A discharge as described in §112.1(b) includes a discharge to navigable waters, adjoining shorelines, or affecting certain natural resources.

We disagree that §112.10(b) duplicates BLM and State regulatory programs. The BLM program is not specifically directed to preventing discharges of oil, and to the extent it meets SPCC requirement, any documentation from it may be usable in an SPCC Plan. Likewise for documentation from State regulatory programs.

§112.10(d) - Where BOP assembly is not necessary, as for certain routine service jobs, such as the installation of a rod pumping unit or the batch treatment of a well with corrosion inhibitor, the owner or operator may deviate from the requirement under §112.7(a)(2), and explain its absence in the Plan. When BOP assembly is unnecessary because pressures are not great enough to cause a blowout, it is likewise unnecessary to provide equivalent environmental protection.

Gauge negative. *Gauge negative* is the pressure condition in a wellbore that results when the pressure exerted by the hydrocarbon reservoir is less than the hydrostatic pressure exerted by the column of drilling fluid in the wellbore. A gauge negative condition will not give rise to a pressure imbalance likely to cause a blowout. See 56 FR 54625.

Category XIV: Requirements for offshore oil drilling, production , or workover facilities - §112.11

Background: Section §112.11 includes SPCC Plan requirements for an owner or operator of an offshore oil drilling, production, and workover facility.

XIV - 1 General and specific requirements - §112.11(a)

Comments: *State rules.* “This section should be deleted because current State spill prevention, water discharge, and hazardous material regulations adequately provide spill protection in inland water areas such as lakes, rivers, and wetlands.” (128)

Response: *State rules.* We disagree with the commenter that these rules are unnecessary because not every State has rules to protect offshore drilling, production, and workover facilities. While some States may have rules, some State rules may not be as stringent as the Federal rules. In any case, Congress has intended us to establish a nationwide Federal program to protect the environment from the dangers of discharges as described in §112.1(b) posed by this class of facilities. Therefore, we have retained the section, as modified. We note, however, that if you have a State SPCC plan or other regulatory document acceptable to the Regional Administrator that meets all Federal SPCC requirements, you may use it as an SPCC Plan if you cross reference the State or other requirements to the Federal requirement. If it meets only some, but not all Federal SPCC requirements, you must supplement it so that it meets all of the SPCC requirements.

XIV - 2 Definition reference; MMS jurisdiction - proposed §112.11(b)

Background: In §112.7(e)(7)(i) of the current rule, the term *oil drilling, production, or workover facilities (offshore)* is defined. In 1991, we redesignated §112.7(e)(7)(i) as §112.11(b), and referenced the proposed §112.2 definition of *offshore oil drilling, production, and workover facilities*. The proposed rule also would have provided that a facility subject to the Operating Orders, notices, and regulations of the Minerals Management Service (MMS) is not subject to part 112.

Comments: We should delete §112.11(b) because it is unnecessary. (121)

Response: The proposed 1991 section referenced the definition of “offshore oil drilling, production, and workover facility,” which is now encompassed within the definition of “production facility” in §112.2. A new sentence would have referenced the exemption of facilities subject to Minerals Management Service (MMS) Operating Orders, notices, and regulations from the SPCC rule. MMS jurisdiction is outlined in Appendix B to part 112. Since none of the proposed language is mandatory, we have deleted it because we have included only mandates in this rule so as not to confuse the regulated public over what is required and what is discretionary. We received no substantive comments on this paragraph.

XIV - 3 Facility drainage - §112.11(b) (proposed as §112.11(c))

Background: In §112.7(e)(7)(ii) of the current rule, requirements for oil drainage collection equipment are described. In 1991, we redesignated §112.7(e)(7)(ii) as §112.11(c), and proposed to require removal of collected material from oil drainage “as often as necessary to prevent overflow, but not less than once a year.”

Comments: *Removal of collected oil.* We should delete the modification that owners or operators remove collected material at “least once a year,” because the current requirement is sufficient. (31, 86)

Response: *Removal of collected oil.* EPA agrees with the commenter’s suggestion that the current rule is sufficient to prevent discharges as described in §112.1(b), and therefore we have deleted the “at least once a year” standard. You must remove collected oil as often as is necessary to prevent such discharges.

XIV - 4 Sump systems - §112.11(c) (proposed as §112.11(d))

Background: Under §112.7(e)(7)(iii) of the current rule, an owner or operator of a facility with a sump system to adequately size the sump and drains must have a spare pump or equivalent method available for removing liquid from the sump, and assure that oil does not escape. In 1991, we redesignated §112.7(e)(7)(iii) as §112.11(d) (redesignated in the final rule as §112.11(c)). We also proposed that the owner or operator must employ a monthly preventive maintenance inspection and testing program to assure reliable operation of the liquid removal system and pump start-up device.

Comments: *Frequency of inspections.* “Semi-annual, instead of monthly inspection and testing of the liquid removal system would be preferable.” (L18)

Response: *Frequency of inspections.* We have retained the current rule language requiring a “regularly scheduled” preventive maintenance program because we believe that the frequency of maintenance should be in accordance with industry standards or frequently enough to prevent a discharge as described in §112.1(b). Whatever schedule is chosen must be documented in the Plan.

XIV - 5 Corrosion protection - §112.11(g) (proposed as §112.11(h))

Background: Under §112.7(e)(7)(vii) of the current rule, an owner or operator must equip tanks with suitable corrosion protection. In 1991, we redesignated §112.7(e)(7)(vii) as §112.11(h) (redesignated in the final rule as §112.11(g)). We also recommended that an owner or operator follow the appropriate National Association of Corrosion Engineers standards for corrosion protection.

Comments: *Industry standards.* We should either delete the proposed recommendation or make it a requirement for new construction. (121) We should modify §112.11(h) to

incorporate other industry recommended corrosion control practices, particularly STI standards. (140)

Response: *Industry standards.* In response to the comment, we have deleted the recommendation because we do not wish to confuse the regulated community over what is mandatory and what is discretionary. These rules contain only mandatory requirements. We expect that facilities will follow industry standards for corrosion protection as well as other matters (see §112.3(d)(iii)), but decline to prescribe particular standards in the rule text because those standards are subject to change, and we will not incorporate a potentially obsolescent standard into the rules.

XIV - 6 Pollution prevention system testing and inspection - §112.11(i) (proposed as §112.11(j))

Background: Under §112.7(e)(7)(ix) of the current rule, an owner or operator must test and inspect pollution prevention equipment and systems periodically, commensurate with the complexity, conditions, and circumstances of the facility. In 1991, we proposed to redesignate §112.7(e)(7)(ix) as §112.11(j) (redesignated in the final rule as §112.11(i)). We proposed to require that an owner or operator use simulated spill testing to test and inspect human and pollution control and countermeasure systems, unless he can demonstrate that another method provides equivalent protection. We also proposed requiring periodic testing and inspection of pollution prevention equipment at least monthly.

Comments: *Frequency of testing.* “Simulation testing on a monthly basis is excessive.” (42, L12)

Annual response drills. MMS requires only annual spill response drills for outer continental shelf operations. “We suggest this is an adequate frequency. Requiring more frequent simulations would overburden facility operators unnecessarily.” (75, L12)

Recommendations instead. We should convert periodic reviewing, testing, and inspecting provisions from requirements to recommendations. We can not justify these provisions either economically or as benefits conferred on society. (42)

Semi-annual testing. “...(A) semi-annual, instead of monthly, requirement for testing and inspection of pollution prevention equipment would be preferable.” (L18)

Response: *Frequency of testing.* We have retained the current requirement for testing on a “scheduled periodic basis” commensurate with conditions at the facility because we believe that testing should follow industry standards or be conducted at a frequency sufficient enough to prevent a discharge as described in §112.1(b) rather than any prescribed time frame. Whatever frequency is chosen must be documented in the Plan.

We disagree that we cannot justify the costs and benefits. This rule is necessary to ensure that systems that prevent discharges function properly.

XIV - 7 Blowout prevention - §112.11(k) (proposed as §112.11(l))

Background: Under §112.7(e)(7)(xi) of the current rule, before an owner or operator drills below any casing string and during workover operations, he must install a blowout prevention (BOP) assembly and well control system. Further, this BOP assembly and well control system must be capable of controlling any expected well-head pressure while it is on the well. In 1991, we proposed to redesignate §112.7(e)(7)(xi) as §112.11(l) (redesignated in the final rule as §112.11(k)), but otherwise repropose without substantive change.

Comments: *Alternatives.* “There are occasions where this is not warranted or impractical to implement.” Exception should be made for drilling below conductor casing. (L12)

Response: *Alternatives.* The question of whether blowout prevention is warranted or impractical or not for drilling below conductor casing is one of good engineering practice. Acceptable alternatives may be permissible under the rule permitting deviations (§112.7(a)(2)) when the owner or operator states the reasons for nonconformance and provides equivalent environmental protection in another way.

XIV - 8 Extraordinary well control measures - §112.11(m)

Background: Under §112.7(e)(7)(xii) of the current rule, an owner or operator must provide extraordinary well control measures in the event of an emergency. In 1991, we proposed to redesignate §112.7(e)(7)(xii) as §112.11(m). We proposed to recommend – instead of to require – that an owner or operator provide extraordinary well control measures if emergency conditions occur (e.g., fire, loss of control). We also recommended varying the degree of control system redundancy with hazard exposure and probable failure consequences. Further, we recommended that an owner or operator include redundant or “fail close” valving in surface shut-in systems.

Comments: We should delete proposed §112.11(m) or make it a requirement. (121)

Response: In response to comment, we have deleted the text of the recommendations from the rules because we do not wish to confuse the regulated community over what is mandatory and what is discretionary. However, we endorse its substance. This rule contains only mandatory requirements.

XIV - 9 Piping; corrosion protection - §112.11(n) (proposed as §112.11(p))

Background: In §112.7(e)(7)(xvi) of the current rule, we require an owner or operator to protect from corrosion all piping appurtenant to the facility. In 1991, we proposed to redesignate §112.7(e)(7)(xvi) as §112.11(p) (redesignated in the final rule as §112.11(n)), and proposed to retain the requirement. We also proposed to recommend – rather than to

require – that the owner or operator discuss in the SPCC Plan the corrosion protection method used, such as protective coatings or cathodic protection.

Comments: We should delete the recommendation that an owner or operator discuss the corrosion protection method used in the SPCC Plan. (121)

Response: In response to comment, we have deleted the recommendation to discuss the method of corrosion protection, because it is surplus. In your SPCC Plan, you must discuss the method of corrosion protection you use. See 112.7(a)(1).

XIV - 10 Written instructions for contractors - proposed §112.11(s)

Background: Under §112.7(e)(7)(xiii) of the current rule, an owner or operator must prepare written instructions for contractors and subcontractors to follow whenever contract activities involve servicing a well or systems appurtenant to a well or pressure vessel. In 1991, we proposed to redesignate §112.7(e)(7)(xiii) as §112.11(s). We proposed to recommend – rather than require – that the owner or operator prepare written instructions for contractors or subcontractors to follow in such circumstances.

Comments: *Liability.* “The regulations appear to mandate involvement and control by an operator over the activities of contractors who perform services on offshore facilities. This creates two very serious problems. First, the contractors are hired to perform special services. The contractor is able to do his work more safely if he is allowed to direct his own activities. Second, operators expose themselves to various types of liability by virtue of the degree of control exercised over contractors.” (42)

Requirement instead. We should continue to require – rather than recommend – that owners or operators prepare written instructions for on-site contractors and subcontractors. (121)

Response: We have deleted the proposed recommendation because we wish to avoid confusing the regulated community over what is mandatory and what is discretionary. This rule contains only mandatory requirements.

Category XV: Relationship to other programs of the rule

XV - A: UST - part 112

Background: In 1991, we noted that a number of underground and aboveground oil storage tanks are subject to both the SPCC regulation (40 CFR part 112) and the underground storage tank (UST) regulation (40 CFR part 280). In §112.1(d)(2)(i) and (ii), we proposed that the calculation of a facility's underground and aboveground storage capacity should not include USTs, as defined in §112.2(v). To avoid duplicative regulation, in §112.1(d)(4), we proposed to exclude from SPCC regulation USTs subject to the technical requirements of 40 CFR part 280, reasoning that the UST program offered comparable environmental protection. We noted that USTs not subject to all of the technical requirements of the UST provisions would be subject to the SPCC requirements. We also noted that the SPCC program would still regulate tanks that are not completely buried, because tanks with exposed surfaces exhibit a greater potential to discharge oil into navigable waters and other surface waters.

Comments: For comments on this issue, see section IV.B of this document.

Response: See section IV.B of this document for response.

XV - B: State programs, SARA Title III, wellhead protection, flood-related requirements, OSHA, and industry standards - part 112

Background: In the preamble to the 1991 proposed rule, we discussed the relationship between the SPCC regulation and other programs, including State programs; the Superfund Amendments and Reauthorization Act (SARA) Title III or the Emergency Planning and Community Right-to-Know Act (EPCRA); State wellhead protection (WHP) programs under the Safe Drinking Water Act (SDWA); flood-related requirements under Executive Order (EO) 11988, "Floodplain Management;" and the Occupational Safety and Health Act (OSHA).

XV-B-1 State programs

Background: See section X.K of this document.

Comments: For comments on State issues, see section X.K of this document.

Response: For responses on State issues, see section X.K of this document.

XV-B-2 SARA Title III and wellhead protection

Background: In 1991, we specified how coordination between Federal, State, and local agencies is possible through additional authorities – SARA Title III in particular. We said that we expected to work closely with States to develop mechanisms for sharing information about facilities and oil discharges to improve environmental protection and

public health. We indicated that the proposal requires an owner or operator to ensure that any SPCC contingency plan is compatible and coordinated with local emergency plans, including those developed under SARA Title III.

We noted that States must adopt and submit to EPA a wellhead protection (WHP) program. We also noted that an owner or operator must comply with both the State WHP program and the SPCC regulations, and that meeting the SPCC requirements did not necessarily ensure compliance with a State WHP program.

Comments: *Support for coordination.* Support for coordination of the SPCC program with SARA Title III. (29, 11) Support for coordination with WHP programs. (27)

Response: *Support for coordination.* We appreciate commenter support.

XV-B-3 Flood-related requirements

Background: In §§112.8(b)(6) and 112.9(c)(3), we recommended – in accordance with EO 11988, “Floodplain Management” – that the SPCC Plan address precautionary measures for facilities in locations subject to flooding. We noted that the National Flood Insurance Program (NFIP) definition of *structures* included ASTs. We described some of NFIP’s requirements and standards, and encouraged owners or operators to consider and comply with the requirements in 44 CFR 60.3 when preparing and implementing an SPCC Plan. We also proposed recommending that an SPCC Plan “address precautionary measures for facilities in locations subject to flooding.” In proposed §§112.8(b)(6) and 112.9(c)(3), we recommended that the SPCC Plan “address additional requirements for events that occur during a period of flooding.”

Comments: *Editorial suggestion.* We should move issues related to flooding from the prevention-related SPCC requirements to the SPCC contingency plan requirements in §112.7(c). (12)

Mitigation measures of NFIP. “At a minimum, EPA should address the mitigation measures of the National Flood Insurance Program (NFIP) ... more definitively in the rule rather than addressing them under the preamble.” “At a minimum, ..., facility owners or operators should undertake the following: 1) Identify whether the facility is located in a floodplain in the SPCC plan; 2) if the facility is located in the floodplain, the SPCC plan should address to what extent it meets the minimum requirements of the NFIP; and 3) if a facility does not meet the minimum requirements of the NFIP, the SPCC plan should address appropriate precautionary and mitigation measures for potential flood-related discharges.” EPA should also consider requiring facilities in areas subject to 500-year events to address minimum NFIP standards. (12)

NPDES rules. The proposed requirements are duplicative of, and may conflict with, storm water regulations. (35)

Recommendation or requirement. We should require – rather than recommend – that NFIP facility owners or operators address precautionary and mitigation measures in the SPCC Plan. (3, 12, 27, 114, 121) Since oil storage facilities could cause significant environmental damage and impact health and safety in a flood, we should require that in areas subject to a 500-year flood event, a facility owner or operator must address NFIP standards in the SPCC Plan. We should clarify that §§112.8(b)(6) and 112.9(c)(3) reflect the preamble language. (12)

Subject to flooding. We should clarify the term *subject to flooding*. (9, 27, 115)

Response: *Recommendation or requirement.*

§112.8(b)(6). We deleted this recommendation because it is more appropriately addressed in FEMA rules and guidance, including the definitions the commenters referenced. We disagree that the proposed recommendation should be made a requirement because flood control plans and design capabilities for discharge systems are provided for under the storm water regulations, and further Federal regulations would be duplicative.

Other Federal rules also apply, making further SPCC rules unnecessary. Oil storage facilities are considered structures under the National Flood Insurance Program (NFIP), and therefore such structures are subject to the Regulations for Floodplain Management at 44 CFR 60.3. Some of the specific NFIP standards that may apply for aboveground storage tanks include the following: (1) tanks must be designed so that they are elevated to or above the base flood level (100-year flood) or be designed so that the portion of the tank below the base flood level is watertight with walls substantially impermeable to the passage of water, with structural components having the capability of resisting hydrostatic and hydrodynamic loads, and with the capability to resist effects of buoyancy (44 CFR 60.3(a)(3)); (2) tanks must be adequately anchored to prevent flotation, collapse or lateral movement of the structure resulting from hydrodynamic and hydrostatic loads and the effects of buoyancy (40 CFR 60.3(c)(3)); for structures that are intended to be made watertight below the base flood level, a Registered Professional Engineer must develop and/or review the structural design, specifications, and plans for construction, and certify that they have been prepared in accordance with accepted standards and practice (40 CFR 60.3(c)(4)); and, tanks must not encroach within the adopted regulatory floodway unless it has been demonstrated that the proposed encroachment would not result in any increase in flood levels within the community during the occurrence of the base flood discharge (40 CFR 60.3(d)). Additionally, the NFIP has specific standards for coastal high hazard areas. See 40 CFR 60.3(e)(4).

§112.9(c)(1). We have deleted the recommendation because we do not wish to confuse the regulated public over what is mandatory and what is discretionary. These rules contain only mandatory requirements. However, we support the substance of the recommendation, and suggest that a facility in an area prone to

flooding either follow the requirements of the NFIP or employ other methods based on good engineering practice to minimize damage to the facility from a flood.

Subject to flooding. Because we have not adopted the recommendation that an owner or operator address precautionary measures for facilities located in areas subject to flooding, we have not defined the term *subject to flooding*, nor have we moved it to §112.7(c).

XV-B-4 OSHA

Background: In 1991, we said that a number of AST owners or operators are subject to OSHA requirements under 29 CFR 1910.106, and we described some of these OSHA requirements. We noted that these requirements are important for implementing effective spill prevention programs and should be incorporated into SPCC Plans using good engineering practice.

Comments: Asks why we said that OSHA requirements are necessary for an effective spill prevention program, when OSHA requirements “stand on their own.” Inclusion of OSHA requirements in the SPCC Plan would be unnecessarily duplicative. (34) “We do not recall an OSHA requirement that dike walls must average six feet in height and that earthen dikes must be three feet in height and two feet wide at the top. Where in the regulations are these requirements located. (101,165, L15)

Response: We agree that OSHA requirements are independent of SPCC requirements. It is not necessary to duplicate compliance with those requirements in an SPCC Plan.

XV-B-5 Industry standards

Comments: We should include applicable industry standards in the SPCC regulation. (46) Our proposal is superfluous for smaller capacity ASTs because ASTs and petroleum hazardous substances are “de facto regulated” by fire and safety authorities (e.g., the National Fire Protection Association, the Western Fire Chiefs Association, and the National Building Code Association). (50) Urges referencing of Steel Tank Institute standards in rule. (140)

Response: Throughout the rule we generally allow for the application of industry standards where the standards are both specific and objective, and their application may reduce the risk of discharges to and impacts to the environment. We recognize that as technology advances, specific standards change. By referencing industry standards throughout the preamble, we anticipate that the underlying requirements of the rule itself will change as new technology comes into use without the need for further amendments. We believe that industry standards today represent good engineering practice and generally are environmentally protective. However, if an industry standard changes in a way that would increase the risk of a discharge as described in §112.1(b), EPA will apply and enforce the present-day standard (or, if that is not possible, its equivalent in risk-assessment terms) rather than the future, less protective standard.

Under the terms of this rule, when there is no specific and objective industry standard that applies to your facility (for example, whether there is no standard or a standard that uses the terms “as appropriate,” “often,” “periodically,” and so forth), you should instead follow any specific and objective manufacturer’s instructions for the use and maintenance or installation of the equipment, appurtenance, or container. If there is neither a specific and objective industry standard nor a specific and objective manufacturer’s instruction that applies, then it is the duty of the PE under §112.3(d) to establish such specific and objective standards for the facility and, under §112.3(d), he must document these standards in the Plan. If the PE specifies the use of a specific standard for implementation of the Plan, the owner or operator must also reference that standard in the Plan.

Throughout today’s preamble, we list industry standards that may assist an owner or operator to comply with particular rules. The list of those standards is merely for your information. They may or may not apply to your facility, but we believe that their inclusion is helpful because they generally are applicable to the topic referenced. The decision in every case as to the applicability of any industry standard will be one for the PE.

For your convenience, we are including a list of organizations in today’s preamble that may be helpful in the identification and explanation of industry standards.

Category XVI: Economic analysis

Background: In 1991, we prepared two preliminary economic analyses: “Economic Impact Analysis of the Proposed Revisions to the Oil Pollution Prevention Regulation,” and “Supplemental Cost and Benefit Analysis of the Proposed Revisions to the Oil Pollution Prevention Regulation.” The first analysis developed cost estimates for the proposed notification along with three other proposed requirements that were determined to result in non-negligible costs to the regulated community. The second analysis estimated the economic effects of the proposed rule based on alternative expectations about how the regulated community would interpret certain proposed revisions. We presented the results of these studies in the preamble to the proposed rulemaking and invited comment on both the methodology used and the results obtained.

XVI - A: Estimated universe of regulated facilities

Comments: *Electrical equipment.* The Economic Impact Analysis underestimated the number of electric utility facilities subject to the SPCC regulations. As many as 100,000 electric utility facilities -- including 48,000 electrical substation-type facilities, 48,000 industrial or commercial customer locations, and 1,600 other locations -- could be subject to the rule. This figure could include 80,000 electric utility sites. As a result, these figures would result in industry-wide costs of \$2 billion and \$1 billion, respectively. (125, 175)

Production facilities. We should revise the number of oil production facilities included in the economic analyses to reflect the final division of responsibility between the Department of the Interior (DOI) and EPA as required by Executive Order (EO) 12777. We did not include in the analyses a facility category encompassing drilling rigs and workover units. Since we included such a category of operations in the regulations, we should include these operations in the economic analyses as well. (128)

Truck stops. Our Economic Impact Analysis (EIA) and Supplemental Cost and Benefit Analysis do not identify *truck stops* as a facility category, and was therefore concerned that the US truck stop industry would not be subject to the SPCC regulations. (43)

Response: *Electrical equipment.* The 1995 SPCC Survey indicated that about 2,600 electric utility industry facilities were regulated by the program. We later increased our estimate to 3,700 to account for possible shortcomings in the development of the original estimate.¹ We recognized the possibility that the large number of transformers and other types of oil-filled electrical equipment that are associated with the estimated 3,700 primary electric utility establishments may not have been fully reflected in the burden estimates for electric utilities included in the 1991 proposed rulemaking analyses. As a result, we have reflected in the Information Collection Request (ICR) and economic analysis for the final rule an increase in the unit burden for a primary electric utility establishment to account for

¹See *Analysis of the Number of Facilities Regulated by EPA's SPCC Program and Analysis of the Applicability of EPA's SPCC Program to the Electric Utility Industry*, June 1996, U.S. EPA.

associated oil-filled electrical equipment (e.g., transformers). As a result of these changes made to the final rule, we expect many utilities to see a decline in compliance costs.

Production facilities. We conducted a survey of oil storage and production facilities in 1995 to better estimate the number of regulated facilities. This survey defined oil production facilities as leases, which corresponds to the definition found in the SPCC rule.

In the oil industry, a lease is generally regarded as a single oil field operated by a single operator. At the time of the survey, we had already signed a Memorandum of Understanding (MOU) with DOI and the Department of Transportation (DOT) (February 3, 1994) that redelegated the responsibility to regulate certain offshore facilities located in and along the Great Lakes, rivers, coastal wetlands, and the Gulf Coast barrier islands from DOI to EPA. As a result, the 1995 survey provided us with a revised estimate of the total number of oil production facilities regulated under the SPCC program, including drilling rigs and workover units. We used this estimate to calculate the economic effects associated with the final rule.

Truck stops. In the 1995 survey, we classified truck stops as gasoline service stations to the extent that they both share the same primary Standard Industrial Classification (SIC) Code (5541). Regardless of their SIC Code, facilities are subject to the requirements of the SPCC regulation based on the total amount of oil storage capacity and the reasonable possibility of a discharge as described in §112.1(b). As a result, all truck stops that have an oil storage capacity greater than 1,320 gallons aboveground or 42,000 gallons underground are subject to the SPCC requirements. However, completely buried storage capacity subject to all of the technical requirements of 40 CFR part 280 or a State program approved under 40 CFR part 281 does not count in the calculation of part 112 storage capacity.

XVI - B: Impacts on small businesses

Comments: *Costs.* We underestimated the cost and level of effort necessary to develop Plans that would meet the requirements we proposed in 1991. (16, 36, 110) The proposed regulation “would significantly impact small operators.” (28) The regulation imposes costs, but does not provide any incremental benefit. (28, 31, 34) Our proposed administrative and training requirements would overpower small facilities. (72, 178) The regulations would drastically impact small oil production facilities, although these facilities rarely have the types of spills the SPCC rule is intended to correct. If adopted, the proposed rule would compel extremely costly facility changes, and would be economically detrimental to Appalachian Producers. (101) The proposed rule could contribute to the elimination of many members of the New York oil and gas production community. (165) We failed to recognize the number of small facilities subject to the rule. (L17)

Regulatory Flexibility Act. The proposed rule would substantially impact small facilities, and we should therefore perform a Regulatory Flexibility Analysis (RFA). (28, 58, 59, 101, 113, 127, 165, L15) Our Regulatory Flexibility Act certification ignores the proposed rule’s impacts on many small shipyards, which qualify as small businesses. (45) The proposed requirements would have a substantial economic impact on the Ohio oil and gas producing industry. We conducted an inadequate economic analysis of the economic

impact upon small entities. Our analysis disregards the Regulatory Flexibility Act requirements. (58) We need to perform an RFA if the proposed rules apply to owners or operators of small aboveground storage tanks. (65)

Secondary containment. The potential danger from a small spill is insignificant compared to the burden imposed on small operations. (149) This regulation is an unwarranted financial burden for owners or operators of small aboveground tanks facilities with secondary containment. (L17)

Small entity. Our method of defining *small entity* led to an inconsistency with the intent of the Regulatory Flexibility Act. We originally applied the eligibility requirements for Small Business Administration (SBA) assistance to define *small entity*, and that when we excluded this method in favor of another, our actions were inconsistent with the intent of the Regulatory Flexibility Act. (58) Appalachian Producers could classify as *small entities* under the Regulatory Flexibility Act. (101)

Response: *Costs.* We disagree with the commenters who stated that the proposed rule would substantially impact small businesses. We conducted a small business screening analysis that we included with the EIA (January 1991). The purpose of conducting this small business analysis was to determine if a formal RFA would be required.

In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives “which minimize any significant economic impact of the proposed rule on small entities.” 5 U.S.C. Sections 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule. This rule will significantly reduce regulatory burden on all facilities, particularly small facilities. For example, the rule exempts the smallest facilities from its scope. It also gives all facilities greater flexibility in recordkeeping and other paperwork requirements. Finally, it gives small businesses and all other facilities the flexibility to use alternative methods to comply with the requirements of the rule if the facility explains its rationale for nonconformance and provides equivalent environmental protection. We have therefore concluded that today’s final rule will relieve regulatory burden for all small entities. After considering the economic impacts of today’s final rule on small entities, we believe that this rulemaking will not have a significant economic impact on a substantial number of small entities.

Regulatory Flexibility Act. An RFA is not required if the rule will not cause significant adverse economic impacts on a substantial number of small entities, which is what the small business analysis concluded. To make this determination, we evaluated baseline and post-compliance financial ratios for typical small firms to evaluate the potential for adverse impacts of bankruptcy. We evaluated four different ratios for firms in 24 different industry categories. Only one of these ratios identified impacts -- the ratio that assessed the proportionate impact to small entities compared to larger entities. For six of our 24 industries, the ratio estimated that small entities could be affected in a manner

disproportionate to the impact on larger entities. However, the remaining three financial ratio tests showed no significant impact to these industries. As a result, we believe we were correct to state that the rule would not have a significant impact on a substantial number of small entities. We arrived at the same conclusion for the final rule as we have included many other revisions from the 1997 proposed rulemaking that are designed to eliminate many of the smaller facilities from the rule as well as to reduce the overall burden to those facilities that remain regulated under the final rule.

The compliance costs used to estimate post-compliance financial ratios reflected both the one-time and recurring costs that we estimated in the 1991 Economic Analysis, which we added together to calculate the maximum estimated first-year burden imposed by compliance. If a firm was not adversely impacted in the first year -- when both the one-time and annual recurring costs occurred -- we assumed that it would not be subject to a significant adverse economic impact in subsequent years.

We also disagree with the comment that we failed to assess the rule's potential impact on small shipyards. We estimated several different financial impacts for numerous facility types manufacturing transportation equipment (SIC 37). Ship building and repairing is a subset of this industrial category (SIC 373) and thus, was captured by our analysis.

Secondary containment. Although we characterized the proposed 72-hour impermeability standard as a baseline, we have not adopted this standard in the final rule. We have retained the current standard which states that dikes, berms, and oil retaining walls must be *sufficiently impervious to contain oil*, which more accurately reflects current industry standards and practices. We also note that several industry standards exist concerning loading areas (e.g., API 2610) and that the final rule merely clarifies existing SPCC requirements.

Small entity. As described in the Economic Analysis for the final rule, we are using SBA definition of small entity. Recently, the categorization of the SBA definitions was revised to correspond to the North American Industry Classification System (NAICS) rather than SIC codes. This change does not affect the SPCC analysis because for the most part, the definitions that applied to facilities based on SIC codes also apply to facilities that are based on NAICS codes, and have the same thresholds for determining if the facility is a small business.

XVI - C: Use of incorrect data

Comments: Disagree with our use of the SBA's FINSTAT database to create a financial analysis of the crude oil and natural gas industries. The database contains business financial information collected between 1976 and 1983 -- the zenith of the petroleum crude and natural gas production industry -- and that simply adjusting the data for inflation does not accurately capture the industry changes following that period. (58, 128)

We should reject the EIA because the document's compliance costs estimates are different than those in the Supplemental Cost and Benefit Analysis. We should have

revisited the EIA using the new estimates to determine if the proposed rule would have a significant impact on small entities. (58)

Response: We recognized the limitations of SBA's FINSTAT data in our 1991 Small Business Analysis. However, we relied on the data to perform our analysis because at the time, it represented the largest, publicly available database with financial information on small, privately held firms. We also chose to conduct our analysis using a different definition of *small business* than that used by the SBA in order to better estimate the proposed rule's impacts on the smallest of the small businesses. Had we used the SBA's definition, we would have included in the analysis over 90 percent of the firms in the affected SICs. As a result, the analysis would have been skewed to estimate the effects on the larger of the small businesses, which presumably would have more resources and would be less impacted by the proposed revisions. By concentrating on the smallest of the small businesses, we were better able to determine the effects that the proposed rule would have on small firms.

We have always treated these provisions as requirements and thus as part of baseline expenditures by regulated firms. For the most part, small facilities should experience a reduction in compliance burden due to the rise in the regulatory threshold, new formatting options, and flexibility to use alternative methods.

XVI - D: Miscalculation of costs

Comments: *Agriculture.* The proposed rule would impose a substantial burden on the agriculture industry, and therefore the industry deserves special consideration. The proposed rule overlaps with other regulations. (139)

Appalachian and Ohio producers. The proposed regulatory changes would significantly impact small oil and gas producers in the Appalachian Basin by regulating almost all tankage in existence, increasing the number of facilities regulated, increasing the extent and complexity of spill contingency plans, and requiring the implementation of new and expanded construction and operations provisions. (28) The proposed revisions will dramatically impact Ohio oil and natural gas producers. (58, 59, 70) The proposed revisions will pose severe and unique economic hardships to Appalachian Producers. (101, 113) The proposed rule's benefits do not match the costs for producers in the Appalachian Basin, and we should regulate only facilities storing large amounts of oil, and not smaller oil and gas producers. The regulatory changes will cause a large percentage of oil and gas wells in the area to cease operations. (165)

Compliance. The small business impact analysis and the EIA cost estimates are sensitive to assumptions of existing compliance. When we relax this assumption in the SBA, compliance costs increase substantially. (182)

Costs: PEs, mandatory requirements, reliance on dispersants. Our economic analysis does not truly represent the costs to the regulated community, because we did not properly analyze the following requirements: the specific Professional Engineer (PE)

provision found in §112.3(d), the mandatory requirements for medium and large facilities; and the §112.7(d)(1) contingency Plan prohibition on reliance on dispersants. (L27)

Definitions: navigable waters, discharge. We have severely underestimated the economic impact on part 112 facilities because the definitions of *navigable waters* and *discharge* have changed drastically since SPCC guidelines were first implemented. (28)

Facility notification. The proposed notification form would pose a greater amount of burden for facility owners or operators than we estimated. Outside persons -- such as outside contractors or upper management -- would be needed to complete the form. The burden would be substantially greater for those facilities without SPCC Plans. (34, 48, 187, 189)

Hours burden. Our hours burden estimate of five to 10 hours per year is too low, and estimates industry burden to be about 144 hours per facility -- 40 hours per year to comply with the regulation, 40 hours to prepare a training program, 40 hours to prepare training program materials, and 24 hours for employee training. (35) Appalachian facilities would incur a greater hours burden than our estimates because such facilities are remote and widely dispersed. (59)

Secondary containment. Our industry cost estimate for the proposed regulations -- of \$441 million in the first year and \$71.8 million each subsequent year -- is erroneously low. (28, 31, 36, 58, 113, 165) Commenters came to this conclusion by calculating compliance cost estimates for the following requirements: 72-hour impermeability for secondary containment and diked areas, and installation of containment systems at all truck loading locations. (28, 165) The majority of owners or operators would have to modify or recertify Plans to meet the proposed regulatory changes. (36) The true compliance costs are *at least* \$892 million, as we estimated in the Supplemental Cost and Benefit Analysis. (58) Due to the financial burden, we should not require owners or operators of aboveground tank facilities with secondary containment and total storage capacity of less than 10,000 gallons to develop a Plan. (L17)

Small business. The proposed revisions would have a severe economic impact on small businesses throughout the country. (50, 58, 110, 139, 182) The proposed rule imposes on small facilities a disproportionately high level of costs as compared to environmental benefits, because such facilities pose a relatively small risk of spills. (62, 125, 156)

Small discharges. The regulation is costly and unnecessary, and we have not established that problems even exist with discharges from small crude oil production facilities. Consequentially, we should gather up-to-date, realistic data to make an informed decision. (101)

Stripper operations. The proposed revisions would cause many small stripper operations to go out of business. (110) The rule disproportionately impacts small entities -- specifically stripper operations -- relative to medium and large entities, because the Petroleum Extraction Industry's *compliance cost to sales comparison* impact is nearly twice as high as other industry's, and exceeds the 110 percent ratio. (L27)

Training. We should clarify which category of individuals must receive mandatory training, because as the rule is currently written, the economic analysis' cost estimate for training is insufficient. (45)

Response: *Agriculture.* Our Small Business Analysis also considered impacts to small farmers, by analyzing small firms in SIC 1 (agricultural crop production) and SIC 2 (agricultural livestock production). For both SIC Codes, we estimated that the proposed rule would have an insignificant impact on these entities. We arrived at a similar conclusion for the final rule, as we have adopted few new requirements and have provided a *de minimis* exemption. In addition, we are no longer regulating the smallest facilities. We have also adopted a number of provisions designed to reduce the overall burden for the remaining regulated facilities, which includes eliminating overlap with other Federal requirements (e.g., UST requirements, flexibility in Plan formatting).

Appalachian and Ohio producers. We considered the potential impacts on small firms in our Small Business Analysis. In our analysis of SIC 131, crude oil and natural gas production, we determined that small firms in this industry were unlikely to close as a result of the compliance costs associated with the proposed rule. However, these firms may experience disproportionate impacts compared to larger firms. In the final rule, we introduced a *de minimis* storage capacity, which may benefit a number of the smaller oil production firms. For the firms that remain in the SPCC program, we are finalizing a rule that promotes flexibility and has few new requirements. As a result, we believe that most oil and gas production firms will experience roughly a 40 percent reduction in burden and costs over time.

Compliance. In response to the comment that our analysis hinges on our assumption of existing compliance, we note that our assumption of a baseline of full industry compliance is consistent with OMB guidelines for preparing regulatory impact analyses. We produced a Supplemental Analysis to estimate the cost of certain provisions of the proposed rule under the assumption that a number of owner or operators have interpreted the proposed changes as substantive changes in their duties to comply with this regulation. The commenter is correct to point out that as a result of the relaxed assumptions concerning baseline activities, estimated compliance costs increased. In the final rule, we have decided not to adopt many of the proposed revisions that would have added to the baseline compliance costs for facilities (e.g., notification). We also are providing a number of revisions in the final rule designed to decrease the overall compliance burden to regulated facilities as well as to offer facilities increased flexibility to meet their obligations under the rule.

Costs: PEs, mandatory requirements, and reliance on dispersants.

Dispersants. In 1991, under §112.7(d)(1), we proposed language clarifying the contents of an appropriate oil spill contingency plan. We omitted the reference to 40 CFR part 109 and instead, specified basic requirements for an oil spill

contingency plan. However, in the final rule, we did not adopt the proposed language and instead retained the existing reference to 40 CFR part 109.

Mandatory requirements. We disagree that we ignored mandatory requirements in our economic analysis for medium and large facilities. We provided cost estimates in the economic analysis for small, medium, and large facilities. We discussed every proposed revision and noted its effect on the regulated community in the analysis. We did not propose nor did we finalize any requirements that are dependent on facility size.

PEs. Final §112.3(d) does not contain a State specific certification requirement for PEs, because the SPCC program is national in scope and therefore State expertise is not necessary.

Definitions: navigable waters, discharge. We have made very little substantive change to the definitions of *navigable waters* and *discharge* since 1973. The new definition of *navigable waters* adds clarity and more examples, and is now consistent with other regulatory definitions of the term. The new definition of *discharge* was made consistent with the Clean Water Act definition as amended in 1978, which exempted certain discharges associated with NPDES permits. This change would not result in an increase in economic impact -- rather, some facilities will no longer be regulated as a result of the revised definition because they are no longer expected to discharge oil, leading to a decrease in economic impact. In any case, any change in economic impact due to this definition revision is the result of the change to the statute.

Facility notification. We have decided to withdraw the proposed facility notification requirement because we are still considering issues associated with establishing a paper versus electronic notification system, including issues related to providing electronic signatures on the notification. Should the Agency in the future decide to move forward with a facility notification requirement, we will repropose such requirement.

Hours burden. We have adopted a model facility approach in estimating the approximate hours burden for facilities to comply with the rule. We adopted this approach to better characterize the diverse universe of regulated facilities. We developed eight different model facilities for this rulemaking -- which we designed to represent the typical facility in each category -- based on oil storage capacity and primary use of oil. We acknowledge that some facilities may experience a higher hours burden and cost for select activities. However, on average, we believe that the hours burden and cost incurred by our eight different model facilities adequately characterize the approximate burden to other facilities with similar characteristics.

Secondary containment. We disagree with the commenters who asserted that we underestimated the cost to comply with the secondary containment and truck loading area requirements. We noted in our 1991 economic analysis that we considered these costs as part of the baseline cost of compliance, which are not affected by the proposed rule. In response to an OMB comment, we later costed out these provisions in a supplemental analysis. In that analysis, we estimated that 78 percent and 88 percent of the regulated

community were already in compliance with these requirements, respectively, and would not be affected by the proposed rule change.

Since we last performed these analyses, API has issued several industry standards, including API 653 and 2610, which address many of the provisions in the SPCC rule. As a result, the final rule relies on current industry standards and practices, where feasible. In the final rule, we withdrew the proposed 72-hour impermeability standard for secondary containment and maintained the current requirement that dikes, berms, and oil retaining walls must be *sufficiently impervious* to contain oil. As a result, the final rule reflects current industry standards and poses no additional requirements on industry.

Small business. We disagree that we failed to analyze the impact of the proposed revisions on small businesses. We direct the commenter to the 1991 Small Business Analysis that is appended to the Economic Analysis wherein we analyze the effects of the rule on small business. We also disagree that costs would be disproportionately high for small facilities compared to the benefits. Although our small business analysis did identify that small facilities in some industries could be disproportionately affected, in no instances did it show that these facilities would be significantly impacted. We expect the impact of the final rule will be less than we originally estimated because we have incorporated several changes to reduce the overall compliance burden (for example, the rise in regulatory threshold - see §112.1(d)(2)(ii)). Also, to calculate total aboveground storage capacity, a facility owner or operator need only count containers greater than 55 gallons. The *de minimis* capacity will eliminate from the rule the smallest of the regulated facilities.

We believe that the cost of compliance for smaller facilities will be less than that for larger facilities because smaller facilities are generally less complex than larger facilities. As a result, it will take less effort to prepare and implement a Plan. The supporting analyses for the final rule provides more detailed explanations of our assumptions concerning this issue.

Small discharges. A small discharge may have a harmful environmental effect. Therefore, small production facilities need prevention measures to avert costly discharges. Recent analysis confirms this statement. See the Denial of petition requesting amendment of the Facility Response Plan rule, 62 FR 54508 *et seq.*, October 20, 1997.

Stripper operations. We disagree that the rule would have an adverse economic impact on stripper wells. We specifically analyzed the impact that the rule would likely have on small businesses involved in crude oil and natural gas extraction (SIC 131). In conducting our closure analysis, we looked specifically at three financial ratios -- return on assets, total debt to total assets, and compliance costs to net sales. These tests failed to indicate that small firms in SIC 131 would be significantly impacted. We did find, however, that small firms in SIC 131 may experience disproportionate impacts compared to larger firms in their industry. This was recognized in the Small Business Analysis.

Training. In the final rule, we have clarified the language regarding training requirements to apply only to oil-handling personnel. See §112.7(f). We have not provided a cost estimate for this requirement, because we have always required a facility owner or operator to provide adequate training for facility personnel. The final rule merely clarifies

that an owner or operator does not need to train all personnel -- only oil-handling personnel.

XVI - E: Additional costs

Comments: *Baseline costs.* Changing the regulatory language from *should* to *shall* will impose additional costs on part 112 facilities. (45, 113, 125, L27) Electrical utilities industry must perform substantial construction as a result of the changes. These changes are impracticable and unnecessary to address any reasonable risk of discharge at electrical facilities. (125) We incorrectly assume that many facilities are already in full compliance with industry standards, and that we should not consider this scenario as the baseline. (L27)

Impermeability requirements. We should not require owners or operators of Appalachian Production facilities to meet the impermeability standards due to the limited environmental benefit and high associated costs. (101) We did not address in the analyses two specific requirements in the proposed revisions -- the requirements for containment systems and diked areas to be impervious to oil for 72 hours. These requirements would require significant capital expenditures for many facility owners or operators. (182)

Paperwork Reduction Act. The time estimates we listed in the Paperwork Reduction Act certification are erroneous, and too low. (45)

PEs. Requiring an independent or outside PE for Plan certification would be extremely expensive for facilities located in remote areas. (59, 65) Requiring the use of an independent or outside PE would be incredibly burdensome to facility owners or operators. (59, 67, 110, 187) Discussions with a PE concerning the use of alternative measures are not negligible costs. Regarding the EIA, we should not have included as a benefit, the requirement for a PE to have no financial interest in the facility because it was not included in the proposed revisions. (L27)

Regular inspection of storage tanks. Requiring regular inspection of storage tanks would impose a significant burden on facility owners or operators. (65)

Vacuum protection, equalizing lines, reinstallation of dike drains. Asks us to clarify whether we had included the cost of vacuum protection installation into the cost analysis. (31, 101, L15) Asks us to clarify that we had included the cost of equalizing lines installation as specified in §112.9(d)(4)(ii) into the cost analysis. (101) We should include in the economic analyses the cost of reinstalling tank dike drains as required in §112.9(c), because owners or operators of facilities have removed over 100,000 forewall drains as a result of the part 112 rules of 1973. (L27)

Weight restrictions. We failed to recognize the substantial costs to owners or operators of determining accurate weight restrictions. (76)

Response: *Baseline costs.* We note that we only costed out in our analysis the incremental effects associated with the proposed regulatory changes. We did not determine the costs of complying with the existing rule. We have always accounted for these requirements in the information collection burden estimates for the rule, and have always assumed 100 percent compliance by the regulated community. Consequently, because we are merely clarifying in the final rule what is already required of the regulated community and because we have accounted for these costs in our continuing analyses of the program, we have treated these costs as baseline in the analyses supporting this rulemaking.

Impermeability requirements. We withdrew the proposed 72-hour requirement. We are maintaining the extant requirement that dikes, berms, and oil retaining walls must be sufficiently impervious to contain oil. Therefore, there are no incremental costs. The revised rule, like the current rule, does not require a specific impermeability for dikes and does not require a specific method of secondary containment at loading areas, and this flexibility is reflected in our cost estimates.

Paperwork Reduction Act. To estimate the burden, we used estimates based on an engineering approach assuming certain small facility characteristics. We note that the actual burden for individual facilities may be greater or less than twelve hours, but consider this estimate to be a fair assumption for the average facility.

PEs. These commenters were principally concerned that we did not fully account for the cost to a facility owner or operator for a PE to visit each facility before certifying a Plan. We note that we did not propose this requirement, but requested comments on it. In the final rule, we require either the PE or the PE's agent to visit and examine the facility before the PE certifies the Plan. An agent might include an engineering technician, technologist, graduate engineer, or other qualified person to prepare preliminary reports, studies, and evaluations after visiting the site. The PE, after reviewing the agent's work, could then legitimately certify the Plan. Also, in the final rule, we allow the PE to be an employee of the facility as well as registered in a different State than the facility is located, in order to approve a Plan. The rationale is that SPCC work is national in scope and therefore State expertise is unnecessary.

We disagree that the burden for a PE to discuss a deviation in a Plan is an incremental cost. Under the current rule, the PE has the same flexibility in the application of good engineering practice. Therefore, such discussion is a baseline activity.

Although we did not propose in 1991 that the certifying PE have no direct financial ties to the facility, we note that we requested comments regarding this issue. In any event, we did not adopt such a provision in the final rule, and note that the benefits of the final rule do not include any consideration of whether the PE has a financial interest in the facility.

Regular inspection of storage tanks. Regular inspection of storage containers is already required under the current rule. Therefore, it is a baseline cost and not an incremental effect of the final rule.

Reinstallation of dike drains. We disagree that we should include in the economic analyses the cost of reinstalling tank dike drains because neither the current rule nor the final rule requires such reinstallation.

Vacuum protection, equalizing lines. Vacuum protection and overflow equalizing lines are measures an owner or operator must consider under the current rule. Our economic analyses only costed out the incremental effects of the proposed rule, not the existing rule's requirements. Therefore, we considered the cost associated with these activities as a baseline cost and we did not include them in our economic analyses.

Weight restrictions. We have deleted the proposed recommendation concerning weight restrictions. Therefore, there are no incremental costs to the owner or operator.

XVI - F: Costs to the electric utility industry

Comments: *Costs.* Our compliance costs for the electric utility industry are erroneously low. Owners or operators of electrical equipment storing 10,000 gallons of oil or less should not be subject to the SPCC requirements because such equipment poses a small amount of environmental risk. (125) We failed to consider the impact of the rule on electrical substations and installations in the current Regulatory Impact Analysis (RIA). As a result, the cost of compliance cited in the RIA is erroneously low. We should prepare a new RIA that accurately reflects the impact of the rule on electric utilities. (130) It would be costly and time-consuming to comply with the SPCC regulations for facilities with electrical equipment. (41, 184, 189)

High viscosity. We should exclude from the proposed secondary containment provisions and integrity testing requirements bulk storage tanks that hold high viscosity petroleum products. We should not require integrity testing and secondary containment for high pour point bulk storage containers, and we did not analyze the costs associated with the proposed requirement. (125)

Impact. If electrical equipment is subject to SPCC regulations, then the number of covered utility industry facilities would increase substantially and the rule would have a greater impact on the electric utility industry than we anticipated. (125, 189)

Regulatory alternatives. In order to comply with the proposed rules, the electric utility industry faces significantly higher costs than we estimated, yet the industry poses an insignificant environmental risk. The commenter provided cost estimates for the electric utility industry to comply with the following requirements: constructing secondary containment and drainage systems; testing tanks for integrity; complying with the impermeability requirement; and writing and implementing Plans at substations. Because of these costs, the commenter suggested the following alternatives:

- State that electrical equipment is not be subject to SPCC regulations.
- Modify the SPCC risk criteria to ensure that only the facilities which pose a real risk of harm are covered by the program.

- Address specific elements of the proposal that are impracticable or impose undue costs for the avoided risk as applied either to electrical equipment or tanks. (125)

Response: *Cost, impact, regulatory alternatives.* We disagree that it would be costly for facilities with electrical equipment to comply with the SPCC regulation, and that subjecting electrical equipment to the regulations would have a greater impact on the electric utility industry than we anticipated. Such facilities must only comply with requirements for oil-filled electrical equipment, and have considerable flexibility in doing so. Furthermore we have exempted the smallest containers and facilities from the rule. Therefore, costs will be mitigated.

In our analysis of the effects of the proposed and final rule, we incorporated a model facility approach. We estimated the costs of complying with the incremental effects of the proposed and final rule changes based on the characteristics assigned to these model facilities. In reality, some facilities may incur greater costs, while other facilities incur lower costs. Since the 1991 rule was proposed, we have redefined our treatment of electric utilities to reflect the slightly greater burden that they may incur to comply with this rule. This change was incorporated in 1997, in response to industry comments concerning our Information Collection Request renewal activities for the SPCC program. We also note that many of the estimates provided by the commenters are not associated with the proposed revisions, and we already require facilities to consider or implement many of these activities.

We note, however, that the final rule provides increased flexibility for an owner or operator. In fact, many of the changes reduce the overall burden to electrical utilities. We clarify in the final rule that electrical equipment is subject only to the general SPCC requirements, and not the more specific requirements for bulk oil storage containers. Secondary containment is still required for all facilities under §112.7(c). If it is not practicable for safety or other valid engineering reasons, under §112.7(d), the owner or operator may provide a contingency plan following 40 CFR part 109, and otherwise comply with the requirements of that section. Furthermore, an owner or operator may deviate from most of the rule's substantive requirements if he explains his reasons for nonconformance and provides equivalent environmental protection. 40 CFR 112.7(a)(2). This provision also cuts costs.

We agree that any equivalent prevention plan acceptable to the Regional Administrator qualifies as an SPCC Plan as long as it meets all Federal requirements (including certification by a Professional Engineer), and is cross-referenced from the requirement in part 112 to the page of the equivalent plan. We do not agree that we should specify acceptable formats. We give examples of those acceptable formats, but those examples are not meant to be exhaustive. See the discussion on §112.7(c) in today's preamble and in this document.

One example of an equivalent plan might include a multi-facility plan for operating equipment. This type of plan is intended for electrical utility transmission systems, electrical cable systems, and similar facilities which might aggregate equipment located in

diverse areas into one plan. Examples of operating equipment containing oil include electrical equipment such as substations, transformers, capacitors, buried cable equipment, and oil circuit breakers.

A general, multi-facility plan for operational equipment used in various manufacturing processes containing over the threshold amount of oil might also be acceptable as an SPCC Plan. Examples of operating equipment used in manufacturing that contains oil include small lube oil systems, fat traps, hydraulic power presses, hydraulic pumps, injection molding machines, auto boosters, certain metalworking machinery and associated fluid transfer systems, and oil based heaters. Whenever you add or remove operating equipment in your Plan that will either increase or decrease the potential for a discharge as described in §112.1(b), you must amend your Plan.

Multi-facility plans would include all elements required for individual plans. Site-specific information would be required for all equipment included in each plan. However, the site-specific information might be maintained in a separate location, such as a central office, or an electronic data base, as long as such information was immediately accessible to responders and inspectors. If you keep the information in an electronic data base, you must also keep a paper or other backup that is immediately accessible for emergency response purposes, or for EPA inspectors, in case the computer is not functioning. Where you place that site-specific information would be a question of allowable formatting, as is the question of what is an “equivalent” plan; an issue subject to RA discretion.

Finally, we note that many of the smaller substation facilities will be exempted from the SPCC regulations due to the changes to §112.1(d) in the final rule – specifically, the introduction of a 55 gallon *de minimis* threshold as well as the elimination of the 660 gallon threshold.

High viscosity. If the owner or operator wishes to deviate from secondary containment requirements, he may only do so because secondary containment is not practicable in the application of good engineering practice. He must also follow the requirements of §112.7(d) in such case. If he wishes to deviate from integrity testing requirements, he must follow §112.7(a)(2). However, both of these activities are baseline activities, and therefore, not incremental costs.

XVI - G: Miscellaneous cost issues

Comments: *Bioremediation.* We are incorrect to assume that Appalachian producers would use off-site disposal for remediation, because the high costs associated with travel time and distance would dictate another method. (101) We should specifically allow the use of bioremediation and on-site disposal following a spill event, because of the high costs associated with off-site disposal. (113)

External heating systems. Objects to the cost to facility owners or operators of installing external heating systems. (76)

Extraction industry - discretionary provisions. The cost of the regulation is greater than indicated in the economic analysis, because the petroleum extraction industry is unable to take advantage of the discretionary provisions for medium or large facilities. The petroleum extraction industry is able to take advantage of the discretionary training provision. (L27)

Farmers. Farmers cannot afford to comply with the proposed regulations, and requested that we create an exemption for farmers based on tank size and risk. (106)

Insufficient information. We have provided insufficient useful information regarding the economic analyses in the preamble to the proposed rule. Therefore, the public cannot understand or comment on the proposed rule. (110)

Jurisdiction, wetlands, sensitive ecological areas. We should reflect in the benefit analysis our change in jurisdiction modified by EO 12777. (128) We should clearly define the jurisdiction of the regulation as well as the terms *wetlands* and *sensitive ecological areas*, because the potential costs of the proposed regulation could be devastating for the regulated community. (139)

Permanently closed containers. We should consider tanks previously removed from service as *permanently closed*. Owners or operators would have to bear significant costs to permanently close tanks so the tanks will not apply towards the storage capacity threshold calculation. (101)

Recordkeeping requirements. Under §112.9(d) and (e), we should not require owners or operators to retain inspection and test records for five complete calendar years irrespective of ownership, due to the financial burden on the facilities. (113)

Scientific rationale. We need scientific justification for the proposed revisions. (127, 132, 139, 160, L27)

Secondary containment. Provides cost estimates for many elements of the proposed rule. (31) Produces compliance estimates based on a small, single facility common to oil and gas production in Ohio. (70) The largest single cost to facilities is the proposed §112.7(c) requirement that dikes, berms, and oil retaining walls must be sufficiently impervious to contain oil. The commenter estimated startup costs to be \$10,425 and annual costs to be about \$260 per facility. (25, 70)

State and local regulation. The proposed revisions are unnecessary because State and local agencies already regulate aboveground storage tanks. (127, 139)

Triennial review. Questions our cost estimates regarding the triennial Plan review and evaluation. The requirement would cost a well operator \$500 for PE certification, and a tank battery operator \$3,000 for PE certification. The requirement would cost owners or operators of onshore production facilities \$2.7 million. (103, 113, 187)

Response: *Bioremediation.* We agree with the commenter that bioremediation may be a proper disposal method. We do not assume any particular facility will use bioremediation, but it is an available option.

Existing program. We disagree that the revisions to the rule would unnecessarily raise the cost of compliance over the current program because the majority of the changes are clarifications of existing requirements. Also, we did not adopt all of the proposed changes, some of which, like facility notification, would have raised costs. Further, the final rule reduces the regulatory burden by: reducing the total number of facilities subject to the rule; introducing flexibility in formatting and recordkeeping; and, by encouraging the use of industry standards to comply with SPCC requirements.

External heating systems. We deleted the proposed recommendation to consider the feasibility of installing an external heating system from §112.8(c)(7). That proposed recommendation is currently a requirement. Therefore, we have reduced costs for an owner or operator.

Extraction industry - discretionary provisions. The rule does not prescribe differing requirements for facilities merely based on size. We have not established discretionary provisions for any facilities. All of the rule provisions are mandatory. However, an extraction facility may avail itself of a deviation in the same manner as any other facility.

Farmers. We disagree that farmers cannot afford to comply with the rule. However, in the final rule, we have raised the regulatory threshold. We no longer regulate a facility that stores 660 gallons or more of oil in a single aboveground tank, so long as the aggregate aboveground storage capacity does not exceed 1,320 gallons. We expect that a significant number of small facilities -- including farms -- will benefit from this change, and expect the majority of small facilities with a single oil tank to no longer be regulated. We refer the commenter to the supporting analyses for more specific estimates on the estimated impacts. We also exempt containers of less than 55 gallons from all rule requirements.

Insufficient information. We disagree that we failed to provide sufficient information regarding the economic analysis in the preamble. We summarized the results of the economic analyses therein. The economic analyses are available for review in the public docket for those wishing to review more specific information on the approach we used to estimate our results. We believe that many of the commenters who were concerned about the costs and benefits of the proposal will find that the changes made in the final rule are to their benefit.

Jurisdiction, wetlands, sensitive ecological areas. The applicability of the rule is clearly set out in §112.1. We have added a definition for *wetlands* in the final rule to provide clarity for the regulated community. We discussed *sensitive environments* in the final 1994 Facility Response Rule. See 59 FR 34070, 34089, July 1, 1994.

In our analysis of the impact of the final rule, we consider the jurisdictional effects of EO 12777 (56 FR 54757, October 22, 1991). Section(b)(1) of EO 12777 delegates to the EPA authority in section 311(j)(1)(C) relating to the establishment of procedures, methods, and equipment, and other requirements for equipment to prevent and to contain discharges of oil and hazardous substances from non-transportation-related onshore facilities. Section(b)(2) of EO 12777 delegates similar authority to contain discharges of oil and hazardous substances from vessels and transportation-related onshore facilities and deep water ports to the Secretary of Transportation. Section(b)(3) of the EO delegates similar authority for offshore facilities, including associated pipelines, other than deep water ports, to the Secretary of the Interior. An MOU between EPA, DOT, and DOI, found at Appendix B to part 112, re delegated from DOI to EPA the responsibility for non-transportation-related offshore facilities located landward of the coast line. Similarly, the MOU re delegated from DOI to DOT the responsibility for transportation-related offshore facilities, including pipelines, landward of the coast line. Thus, only a small fraction of SPCC-regulated facilities are affected by the EO and MOU, and the majority of those facilities were already taken into account in the benefits analysis.

Permanently closed containers. We believe that containers that have been permanently closed according to the standards prescribed in the rule qualify for the designation of “permanently closed,” whether they have been closed before or after the effective date of the rule. Containers that cannot meet the standards prescribed in the rule will not qualify as permanently closed. To clarify when a container has been closed, we have amended the rule to require that the sign noting closure show the date of such closure. The date of such closure must be noted whether it occurred before or after the effective date of this provision. Some States and localities require a permit for tank closure. A document noting a State closure inspection may serve as evidence of container closure if it is dated.

Recordkeeping requirements. We agree that a requirement to retain records for five years is too long, and have withdrawn the proposed requirement in favor of the general requirement in §112.7(e) to maintain records for three years.

Secondary containment. We appreciate the comments providing associated cost of compliance data. We note that we have improved the methodology used to estimate the effects of the rule by expanding the types of model facilities used in the analysis. The costs we have estimated for each model facility type are approximations that are meant to reflect average costs to a facility having similar characteristics as our model facility. In reality some facilities will experience higher or lower costs than what we have estimated. Overall, however, we believe that this technique gives us a reasonable estimate of the program’s entire costs and cost savings.

Scientific rationale. We believe that each of the revisions to the SPCC rule being adopted have an adequate scientific, policy, and legal basis. In response to comment, we have not promulgated a number of proposed provisions.

State and local regulation. We disagree that the rule is unnecessary because State and local agencies already regulate aboveground storage tanks. Both the States and EPA

have authority to regulate containers storing or using oil. We believe State authority to regulate in this area and establish spill prevention programs is supported by section 311(o) of the CWA. Some States have exercised their authority to regulate while others have not. We believe that State SPCC programs are a valuable supplement to our SPCC program. We do not preempt State rules, and defer to State law that is more stringent than part 112.

We also note that you may now use a State plan as a substitute for an SPCC Plan when the State plan meets all Federal requirements and is cross-referenced. When you use a State plan that does not meet all Federal requirements, it must be supplemented by sections that do meet all Federal requirements. At times EPA will have rules that are more stringent than States rules, and some States may have rules that are more stringent than those of EPA. If you follow more stringent State rules in your Plan, you must explain that is what you are doing.

Triennial review. We have extended the time in which an owner or operator must review the Plan from at least once every three years to at least once every five years. As a result, we expect that facility owners or operators will experience an overall reduction in the annualized cost of conducting such a review. The costs associated with this activity are baseline costs that we have already determined in numerous information collection burdens. The impacts of this change are discussed in the supporting analyses to the rule. Further, we have clarified in the final rule that a PE must certify only technical Plan amendments.

XVI - H: Miscalculation of benefits

Comments: *Costs, benefits.* The benefit values calculated in the analyses are too great, and the economic benefit of applying the proposed changes to oil and gas production facilities is far outweighed by the cost. The benefits of the proposed changes would be at most in the tens of thousands of dollars per year. (28, 165) We failed to accurately predict the costs, and we overestimated the benefits of the proposed regulation in spite of the economic analyses. (35) We quantified the benefits in incredibly broad terms, and we counted spill reductions as benefits, even though we already counted these as benefits of prior regulations. (128)

Discharges avoided. Disagrees with our estimate found in the Supplemental Cost and Benefit Analysis for the benefits associated with avoiding cleaning up an oil spill. The cost to clean up such a spill is considerably less, and therefore our benefit estimation is too high. (101) Although we cite as a potential benefit the increased revenue from sales of petroleum products not lost in spills, a facility owner or operator already strives to avoid spill events wherever possible due to the stated incentive. (L27)

Facility notification. We have not described how we monetized the benefits of the proposed notification form and regulatory revisions. However, we cannot possibly monetize these benefits without first identifying any problems with the current SPCC

program. (31, 34) We should not count as a benefit compliance with the proposed notification provision, and noted that this action is actually a burden. (128)

Human health and the environment. The benefits resulting from the proposed regulations will have little if any benefit in protecting human health or the environment and do not justify the standards we are requiring for facilities subject to the part 112 requirements. (28, 74, 110, 113, 137, 149, 160, 192)

Response: *Costs, benefits.* We disagree that we failed to accurately predict the costs, and that we overestimated the benefits of the rule in spite of the economic analyses. We believe that we have adequately explained in our economic analysis the methods used to predict costs and benefits. The final rule will reduce costs by millions of dollars a year for regulated facilities.

Discharges avoided. Our method of calculating benefits for the 1991 proposal involved an attempt to quantify the value of avoided oil spilled and associated clean-up costs that would result from the proposal. While some commenters believe that we may have overestimated the unit cost of clean-up for some types of facilities, we believe that our overall estimate was fairly reliable because we most likely underestimated clean-up unit costs for other types of facilities. As we noted in the analysis, “the cost to clean up oil spills may vary substantially, depending on a number of parameters including: the environmental medium that is contaminated; the sensitivity of the environment to spills (spills to wetlands); the size of the spill; the type of oil; and the length of time it takes for a response action to begin, among others.” Since we initially performed this analysis, there has been substantial development in this area as a result of the Oil Pollution Act of 1990 (OPA).

Facility notification. We have withdrawn the facility notification proposal. Therefore, there are no costs associated with it in the final rule.

Human health and the environment. We disagree that the rule will have little if any benefit in protecting human health or the environment and does not justify the standards we are requiring for facilities subject to the part 112 requirements. We believe that the final rule will reduce the overall compliance costs to industry without sacrificing any protection to the environment. As previously noted, the measurable benefits attributable to the final rule are related to the estimated reduction in associated burden for SPCC-regulated facilities. We believe this burden reduction will be approximately 40 percent for the regulated universe. This reduction is principally associated with our decision to incorporate many industry standards and practices into the rule, along with the decision to extend the length of time in which a facility owner or operator must review and evaluate the Plan. We also have adopted a number of revisions designed to increase the flexibility a facility needs to comply with the requirements of the rule. We have not adopted the notification provision and the 72-hour impermeability standard for secondary containment, which many commenters opposed based on associated costs. Further, we have decided to no longer regulate small facilities storing less than 1,320 gallons in a single aboveground container.

We note that while we did not describe how we monetized the estimated benefits of the proposed rulemaking in the preamble, we did provide a cite to the Supplemental Cost and Benefit Analysis of the Proposed Revisions, which was available to the public throughout the rulemaking process.

Category XVII: General comments

XVII-1 Support or opposition to the proposed rule

Comments: *Support for proposed rule.* The proposed revisions clarify and strengthen the SPCC program and protect the navigable waters of the United States. (4, 27, 54, 64, 67, 81, 82, 105, 107, 115, 135, 136, 142, 147, 153, 158, 161, 164, 181, 184) The proposed amendments would “enhance the safety of the SPCC program.” (54) The revisions would make the regulation clearer and facilitate compliance. (136) The revisions would make the SPCC program enforceable. (184) The proposed changes would help prevent major problems with aboveground storage tanks and piping systems. (L1) There would be “no dual regulation in offshore areas.” (L12)

Opposition to proposed rule.

Burdensome or costly. Implementing the proposed rule would be burdensome. (83, 91, 102) The proposed requirements would force the regulated community to ignore the rule, or go out of business. (122) The proposed requirements would impose expensive and unnecessary administrative burdens, monitoring and reporting requirements, and other excessive compliance costs on a facility. (35, 86, 111, 113, 131, 184, 189, 192, L35) We must consider drafting regulations that protect the environment, and are affordable to this country’s businesses. (139)

Current rule adequate. Current SPCC regulations are adequate to assure the protection mandated by the CWA and the Oil Pollution Act (OPA). (35, 71, 101, 192, L30) Existing regulations are adequate, and further regulatory measures are not necessary. (110, 149)

Decreased flexibility. Adopting the proposed requirements would limit or curtail the flexibility in the current regulation. (35, 91, L30) Adopting our proposals would not benefit the environment. (35, 86, 148, L35) The proposed rule is “highly inflexible.” (184)

Interpretation. The proposed revisions have been “subject to incorrect and unnecessary interpretation.” (100, 103)

OPA. We should not promulgate the proposed revisions. (101) The proposed rulemaking did not implement the Oil Pollution Act of 1990 (OPA). (31, 34, 35)

Production facilities. Oil and gas exploration and production and gas processing industries have been “highly effective in implementing the SPCC program and in controlling releases of oils to the waters of the United States.” Our “substantial” proposed revisions were unjustified given the record of losses in the production sector, and the relatively small size and isolated location of most production facilities. (86)

Reduced environmental protection. In some cases, the proposed rule could “decrease the protection afforded under the current rule.” Many operators prepare SPCC Plans for all storage facilities -- regardless of how close the facility is to navigable waters. Overly burdensome SPCC Plan requirements such as we proposed, could discourage owners or operators from continuing that practice. (86)

Substantial risk. Supports the proposed rule only insofar as it addresses the standards applicable to facilities that pose a substantial risk to navigable waters of the U.S. because they store or handle large bulk quantities of oil. (156)

Technically ill-conceived. The proposed regulation is technically ill-conceived. (110)

Unnecessary. The proposed regulations are unnecessary. (35, 71, 113) The proposed requirements would result in a considerable burden and expense for facilities, with no commensurate environmental benefit. (88, 153, 167) The proposed changes would not improve the overall effectiveness of oil pollution program regulations. (103)

Vague. Certain proposed provisions are unclear and technically impractical. (67, 83, 91, 100, 102, 103, 131)

Response: *Support for proposed rule.* We appreciate commenter support.

Opposition to proposed rule. We disagree with the general opposition to the proposed changes. We proposed the changes largely to make part 112 clearer and simpler, to reflect expanded jurisdiction under the CWA, and to respond to recommendations of the SPCC Task Force and General Accounting Office report. We have considered comments on the technical viability of the proposed requirements and made many changes in the rule based on those comments.

Further, the final rule contains a number of provisions designed to decrease regulatory burdens on an owner or operator. It gives him greater flexibility than the current rule by allowing him to choose methods that best protect the environment. We maintain the good engineering practice standard which encourages an owner or operator to use industry consensus or other appropriate standards, rather than prescribing particular procedures, or monitoring or inspection schedules. For most of the substantive requirements, when a facility owner or operator can demonstrate that a particular provision is infeasible based on facility-specific circumstances, an owner or operator may substitute alternative measures that provide environmental protection equivalent to part 112 requirements.

In 1991, we prepared two preliminary economic analyses to support the proposed rule, including an initial economic impact analysis under Executive Order (EO) 12291 and a supplemental cost and benefit analysis. For the final rule, we have assessed the economic effects as required by EO 12866 and relevant statutes. We think that we have

considered costs and burdens adequately, and invite the interested reader to review the Regulatory Analyses at the end of the preamble to the rule we adopted and the docket for this rulemaking.

XVII-2 Editorial changes and clarifications

Comments: *ANPRM.* Asks us to use an Advance Notice of Proposed Rulemaking (ANPRM) for discussing issues on which we simply asked for comments. (121)

Plain language, “countermeasure.” We should use the active voice and simple English. Part 112 is unnecessarily wordy. (121) We should drop the “s” from *countermeasures* in the proposed rule. (7, 9, 121) We should make the same change in 40 CFR part 264. (7)

Recommendations. Asks us to simplify the regulation by omitting recommendations or discretionary provisions. Suggests that we develop a separate “Code of Good Practice” for recommendations. We would have difficulty enforcing provisions where we did not use an imperative statement. (44, 121)

Syntax and grammar. Several commenters made suggestions regarding syntax and grammar. (27, 54, 76, 79, 100, 121, L26) .

Response: *ANPRM.* We believe that it would have been redundant to use an Advance Notice of Proposed Rulemaking (ANPRM) for discussing issues on which we simply asked for comments in 1991. The 1991 preamble was an appropriate mechanism for the comment request.

Plain language, “countermeasure.” We have made changes to correct grammar and typographical errors, to promote consistency, and used a plain-English format to make part 112 clearer and easier to use. A plain English format includes maximum use of the active voice; short, clear sentences; and, in this rule, a summary of the major regulatory changes. Using this format is part of our continuing regulatory reinvention efforts. We have revised the term “countermeasures” to read “countermeasure” in the term Spill Prevention, Control, and Countermeasure Plan. We cannot revise “countermeasures” in 40 CFR part 264 as part of this rulemaking because we did not propose any changes to that part.

Recommendations. We have not included discretionary provisions in the final rule because we do not wish to confuse the regulated community by being unclear about what is mandatory and what is discretionary. We will provide guidance or policy statements, as necessary, that will include some or all of these recommendations. In the absence of such guidance or policy statements, we urge an owner or operator to look to current industry standards for guidance on technical issues.

Syntax and grammar. We have corrected errors in syntax and grammar.

XVII-3 Public participation and call for more data

Comments: *Basis for rule.* We did not discuss what major release or spill scenarios compelled us to propose changes, nor why the proposed changes would improve the situation. We should show more data and empirical evidence that demonstrate why the regulation is necessary. We should re-propose this rule based on new data, which display and target the design and operating problems that require improvement. (148) Our data is deficient because we did not use Petroleum Extraction Industry statistical data or State data. (L27)

Liner Study. Section 4113 of OPA required the President “to conduct a liner study, report the study results to Congress, and implement the study recommendations six months after the report. We have not completed the study and have not made it available to commenters. We should withdraw proposed regulations on secondary containment until we complete the study, and the affected industry had an opportunity to comment on the study during rulemaking. (32) We should release this study for public comment before submitting it to Congress so that we have the full benefit of industry’s practical experiences with liners and other means of containment. (54)

SPCC Task Force. We left out many small businesses in America by consulting only with American Petroleum Institute (API), and not with the Oklahoma Independent Petroleum Association (OIPA) or the Independent Petroleum Association of America (IPAA). (11) We should have included Professional Engineers on the SPCC Task Force (Task Force). (11,110) Criticizes the Task Force because it was composed entirely of Federal and State regulatory officials and notes that there were no representatives from affected industries or State oil and gas commissions. The Task Force could not have evaluated regulatory issues impartially, or have received sufficient input regarding potential regulatory impacts on industry. The Task Force report was of extremely limited value as a basis for rulemaking. (32)

Response: *Basis for rule.* We disagree that we did not state our purpose in the proposed rule, and refer the reader to our extensive discussion of the proposals in the NPRM. Similarly, we cannot agree that our data and analyses are deficient, and refer the reader to the rulemaking docket for our supporting data and analyses. We note that we receive additional data from industry representatives and other interested persons which we considered throughout our rulemaking process.

Liner Study. We completed the liner study and published a report to Congress in May 1996. The study is available to interested readers on our website at epa.gov/oilspill.

SPCC Task Force. Federal regulatory agencies must observe various procedural requirements to assure that there is adequate opportunity for the public to participate in rulemakings. While the membership of the task force may not have included certain groups, everyone had the opportunity to comment on the proposal. We considered all comments and made many changes based on them.

XVII-4 Adequacy of existing Plans

Background: In 1991, we requested comments on whether existing SPCC Plans were adequate to meet the requirements of the regulation we proposed. We requested comments to help us estimate the extent to which the proposed requirements may impose new compliance costs.

Comments: Existing SPCC Plans would not meet the provisions we proposed. (16, 36, 79, L8, 129) Owners or operators would have to modify existing Plans if we adopt the new provisions included in the proposed regulation. (16, 79, L8)

Response: Many Plans will only need to include cross-referencing modifications. An owner or operator will find it necessary to modify his existing Plan to meet the requirements of the final rule, if only to cross-reference existing requirements to redesignated requirements. To reduce the burden, we permit the use of a Plan supplement which cross-references the location of requirements listed in the revised rule with the equivalent requirements in an existing Plan. In the final rule preamble, we provide a table to assist owners or operators with this cross-referencing.

XVII-5 Other comments

Comments: *Comments.* We should consider all comments on the proposed regulations, including those from the regulated community. (135)

Comprehensive program. The proposed regulation will be ineffective in preventing spills, unless we substantially increase staff for facility inspections and enforcement. Using part 112 in 1991 would have lessened the justification for a new up-to-date and comprehensive national aboveground tank law. We should work with Congress to develop a comprehensive spill prevention program, rather than follow a piecemeal approach to oil spill prevention. (111)

Drafting. When we draft regulations, we should acknowledge company efforts. (139) In promulgating the final rule, we should eliminate “broadly written statements that would expand the coverage of this proposal without increasing the environmental benefit.” (L6)

Generic Plans. We were incorrect in assuming that a widespread practice for owners or operators of large companies is to develop generic SPCC Plans without considering specific plant requirements. (39)

Reducing pollution. We should provide incentives for reducing the potential for oil pollution of navigable waters. (L12)

Substantive changes. The proposed regulations represent “substantial requirements and not mere clarifications.” Cites substantive requirements and “should to shall” changes as examples. By failing to give fair notice of the nature of our proposed revisions to the Oil

Pollution Prevention regulations, we did not provide for adequate public participation in the rulemaking process, as we are required to do under 553(b) of the APA. (32)

Response: *Comments.* We have carefully considered all comments, and made many changes based on them. The final rule protects the environment while reducing the information collection burden on the regulated community.

Comprehensive program. We appreciate the commenter's concern regarding our program funding. We agree that a comprehensive approach to oil pollution prevention is best. To further that approach, the SPCC program and the UST program have worked together to eliminate duplicative regulation in this rule. Except for facility diagram requirements, we have eliminated from the SPCC program all completely buried tanks subject to all of the technical regulations of 40 CFR part 280 or of a State program approved under 40 CFR part 281.

Drafting. We agree that we should eliminate "broadly written statements that would expand the coverage of this proposal without increasing the environmental benefit," and believe we have done so. We also acknowledge company efforts to protect the environment and to comply with the rule.

Generic Plans. We do not assume and never have assumed that it is a widespread practice for owners or operators of large companies to develop generic SPCC Plans without considering specific plant requirements. We do acknowledge that most companies attempt to comply with the rule. In response to the comment that we should provide incentives for reducing the potential for oil pollution of navigable waters, we agree and have done so. We have retained the flexibility in the rule that permits an owner or operator to use alternate methods to achieve pollution prevention goals.

Reducing pollution. We agree that we should provide incentives for reducing the potential for oil pollution of navigable waters and believe we have done so in this rule. Incentives include flexible formatting and recordkeeping, use of industry standards, and the availability of deviations for most substantive provisions.

Substantive changes. We disagree that "the should to shall to must" change is substantive. See the discussion in section IV.C. in the preamble to today's final rule. The changes to the text of existing substantive requirements are mostly clarifications. There are few new requirements in the final rule. Moreover, we discussed the "should" to "shall" issue in the preamble of the proposed rule.

XVII-6 Request to extend the comment period and hold public hearings

Background: In 1991, we said that we would consider comments submitted on or before December 23, 1991, which was 60 days after we published the proposed rule. We also said that if the comments we received indicated sufficient need, we would consider holding a public hearing

Comments: *Extension of comment period.* Many commenters asked for 30 to 60 more days to comment. (13, 17, 18, 19, 20, 31, 42, 58, 108, 110, 120, 122, 142, 160, 184, L22). Requests more time, asserting that the rule was lengthy and complicated. (13, 20) Requests more time to review the economic, fire safety, and environmental consequences of our proposed changes. (17) End-of-the-fiscal-year requirements prevented reviewing the proposed rule in the 60-day time frame. (18, 19, 20) Although we allowed commenters 60 days to respond to our proposed changes, commenters had only 45 days by the time a copy of the *Federal Register* arrived in the mail. The commenters also noted that they had to wait to receive copies of the economic analyses that we made available through the mail upon request. (31, 110) Requests an extension to review the equipment upgrade and soil removal requirements. (160) Asks for an extension for time to visit and learn more about facilities affected by the proposed changes. (184) A State rule revision process is insufficiently advanced to allow commenters to provide comments within our time frame. (L22)

Public hearings. We should hold public hearings to discuss the proposed changes. (11, 31, 35, 42, 79, 110, 129, 142, L28) Public hearings would benefit small businesses without staff to monitor the *Federal Register*. (11) Asks that we hold public hearings in locations throughout the United States for small businesses without the money to travel to Washington, D.C. (11, 31, L28) Holding public hearings would give the regulated community a chance to present an accurate assessment of the costs associated with the proposed changes. (31) Asks us to grant an extension and hold public hearings to give petroleum exploration and production facility owners or operators an opportunity to inform us about the broad impacts of the proposed rule on these facilities. (142)

Response: *Extension of comment period.* While we did not extend the comment period for the 1991 rulemaking, we believe that a 60-day comment period was adequate, and consistent with other Federal agencies. We note that we considered comments received as late as April 1993.

Public hearings. We decided that there was insufficient need for a public hearing because the written comments provided exhaustive arguments on each side of nearly every relevant issue.

XVII-7 Support for comments submitted by other commenters

Background: We received many comments from writers who simply endorsed a letter or position of another writer.

Comments: Support for the Utility Solid Waste Activities Group comments on part 112. (92, 100, 130, 138, 163, 164) Support for Utility Water Act Group comments. (100, 120, 130, 138, 163) Support for Ohio Electric Utilities Institute comments. (163) Support for comments from the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association. (138)

Support for comments from the American Petroleum Institute. (64, 83, 85, 91, 94, 96, 97, 102, 133, 173, 174) Support for the Rocky Mountain Oil and Gas Association comments. (174)

Support for comments from the Independent Petroleum Association of America. (160, 167) Support for comments from the Mitchell Energy and Development Corporation and the American Exploration Company. (160) Support for comments from the Institute of Shortening and Edible Oils, Inc. (30), and the Ohio Oil and Gas Association (59).

Response: For responses to specific comments, refer to the appropriate sections of this document.